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Tariff Methodology for the Energy Sector of Mongolia

Final Report

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Tariff Methodology for the Energy Sector of Mongolia

For the Energy Regulatory Authority of Mongolia

June 2003

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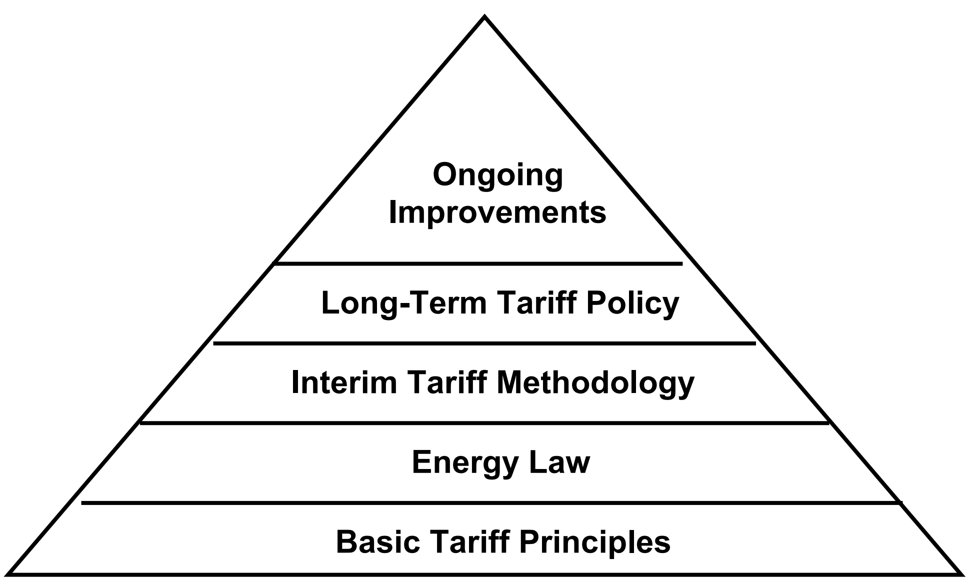
EXECUTIVE SUMMARY

The Government of Mongolia requested the U.S. Agency for International Development to provide assistance on the restructuring of its energy sector. The goal of the Energy Sector Restructuring Project (ESRP) is to assist with the implementation of the new "Law of Mongolia on Energy" (Energy Law) aimed at restructuring the sector in a more commercially based environment that would shed unnecessary fuel, equipment, and labor cost burdens, creating efficient energy facilities and operations that yield a consistent and profitable contractual, regulatory, and industrial framework. This framework will attract investment to support new supply facilities to meet energy demand at least cost while improving supply, reliability, and efficiency.

One of the tasks is to provide technical assistance to the Energy Regulatory Authority (ERA) of Mongolia on a variety of issues, including tariffs. The primary purpose of this report is to provide the ERA with a tariff methodology that it can use as one of its important tools to effectively regulate the power sector of Mongolia. It can also be utilized to inform interested stakeholders (The Government of Mongolia, International organizations, potential investors in the sector, etc) of the tariff methodology so they can make informed decisions.

This report is the product of nearly two years of effort working with the Energy Regulatory Authority since its inception in April 2001, following the passage of the Energy Law. The ERA has a very solid foundation upon which to build. Mongolia currently has a tariff situation that puts it far ahead of most developing countries. For the majority of the energy sector, the Central Electricity and Heat System, licensee and retail tariffs cover approximately all financial costs of the Licensees for providing electricity and heat, although cross subsidies between the electricity and heat functions and among individual customer classes exist. An Interim Tariff Methodology was developed and used to establish licensee and retail tariffs in December 2001, in accordance with the Energy Law. Our task here is to build upon that solid foundation to develop the longer-term tariff methodology as depicted in Exhibit ES.1

Exhibit ES.1 Building Blocks of the Tariff Policy



On May 27, 2003 the draft of this report was provided to ERA, Licensees, Ministry of Infrastructure, Ministry of Finance and Economy, State Property Committee, and USAID. At the request of USAID, a copy was subsequently delivered to the World Bank in Washington, DC. On June 9, a meeting was held to answer questions and receive comments on the tariff report. The meeting was attended by representatives from ERA, 8 Licensees, Ministry of Infrastructure, State Property Committee, and USAID. Written comments on the draft report were received from ERA, National Dispatch Center, Darkhan Power Station, and Darkhan Selenge Electricity Network. This review added transparency to the development of the tariff methodology and gave the Stakeholders an opportunity to have input to the result.

There are certain basic economic principles relating to the development of electricity tariffs that apply generally to any market structure. Chapter 2 of this report is dedicated to a review of those principles. The second building block of the tariff methodology is the Law of Mongolia on Energy. Chapter 3 highlights the provisions of the law dealing with tariffs and related issues.

The starting point for the development of any tariff is the determination of the revenue requirement of a licensee, focusing on determining the appropriate cost elements to be allowed for cost recovery (Chapter 4). In the newly restructured sector, retail tariffs are basically the result of applying the tariffs of the relevant components of generation, transmission, distribution, and retail supply in an appropriate manner to determine the cost to serve each customer class. Tariffs for the individual Licensees must, therefore be developed as follows:

Generators in the Central Electricity System	Chapter 5
Wholesale Market Pricing	Chapter 6
Transmission	Chapter 7
Distribution and Retail Electricity Supply	Chapter 8
Heat Networks	Chapter 9
Isolated Systems	Chapter 10

Once Licensee tariffs are developed, other tariff related issues must be addressed including Performance Based Regulation (Chapter 11), Subsidies (Chapter 12), Lifeline Tariffs (Chapter 13) and Demand Side Management (Chapter 14).

We then have all the tools in place to determine Retail Tariffs. Next we must focus on the Distribution/Retail Supply Licensees that are responsible for developing retail tariffs. A revenue requirement for serving retail customers must then be developed and allocated to customers using a Cost of Service methodology to assign costs to customer classes based on their energy usage characteristics, primarily the voltage at which they receive service, as covered in Chapter 15. The next step is to use the Cost of Service information to design the actual tariffs in Chapter 16.

In order for ERA to effectively carry out its regulatory oversight role, including tariff determination, it must have access to information from Licensees on an ongoing basis and in a tariff proceeding. Chapter 17 deals with periodic reporting and the requirements of Licensees to provide information to the ERA on a monthly, quarterly, and annual basis. Chapter 18 outlines the requirements for the tariff application and approval process.

Highlights of the tariff methodology being proposed include:

A. Basing tariffs on a revenue requirement that includes all the financial costs of a Licensee, including a return on equity.

B. Consideration of the Single Buyer market structure in which all generation is sold to the Wholesale Market (Single Buyer) and the power is then sold at a uniform price to Wholesale Market Customers (currently Distribution/Retail Supply Licensees).

C. Determination of two-part tariffs for generators to include in their Power Purchase Agreements with the Single Buyer. The Energy Tariff recovers the variable costs of generation and the Availability Tariff recovers the fixed costs of the power station. In addition to providing a fair cost recovery mechanism and incentive for the Generation Licensee, the Dispatcher will have the information needed to more effectively implement Economic (or Merit Order) Dispatch.

D. Establishment of a Fuel Cost Adjustment Mechanism to adjust the Energy Tariff for each power station in the event that the unit price of coal, mazut, or rail transportation deviate from the levels used to develop the base tariff.

E. Determination of a Wholesale Market Price for electricity sold by the Single Buyer to the Distribution/Retail Supply Licensees that utilizes a uniform price per kWh. Since immediate application of this mechanism would result in significant tariff increases for Ulaanbaatar and Darkhan Distribution Networks and significant decreases for Erdenet Distribution Network, however, a two-year phase in mechanism is utilized.

F. A Wholesale Market Price for electricity sold by the Single Buyer to the Distribution/Retail Supply Licensees that utilizes a fixed price per kWh for a period of six months. Semiannually, any imbalance in the wholesale market account caused by the use of the fixed price will be reconciled and billed to customers over the subsequent six-month period.

G. A Transmission Network Service Tariff determined by using a “Postage Stamp” method, resulting in a fixed uniform price per kWh for use of the transmission network.

H. Distribution Licensee Tariffs determined for 3 different voltage categories (35 KV, 10 & 6 KV, and 400 volts and below).

I. Implementation of a Cost of Service methodology that determines the cost to serve retail customers at 4 different voltage levels:

- 110 KV
- 35 KV
- 10 and 6 KV
- 400 volts and below

J. A Retail Tariff Design methodology that bases tariffs on the Cost of Service by voltage and then, within those voltage categories, also has tariffs for unique customer classes (e.g. Time-of-Use, Street Lighting, etc.).

K. A recommendation that the practice of having the Customers own their meters be discontinued. The meters should be owned by the Distribution Licensees, as required by the Energy Law. A 5-year phase in period is provided to accomplish this gradually.

L. A proposal to move each customer class closer to the cost to serve them, gradually over a period of years.

M. A recommendation to reduce the subsidy from electricity to heat gradually to (1) bring the cost of central heat closer to the cost of supply and more in line with the cost of heat incurred by households not connected to a central system and (2) to relieve some of the pressure on electricity tariffs.

N. A Lifeline Tariff to address the needs of low-income households. The tariff provides for a "lifeline" amount of electricity per month to meet the basic needs of a household to be priced at a relatively low level. Electricity usage above that amount would be priced at the full cost, providing funding for the lifeline subsidy and also an economic incentive for higher use customers to conserve.

O. Provisions for Incentive Regulation, especially in the areas of Generation and Distribution.

P. Recommendations for management of the tariff process including periodic reporting by Licensees to the Energy Regulatory Authority (ERA), information requirements for tariff applications of Licensees, and basic procedures for the ERA to follow when deciding on tariff applications.

It is important to realize that this is not "ERA's Tariff Policy" alone. It is the Tariff Policy for the Energy Sector of Mongolia, and all the Stakeholders involved, including the Government, ERA, Licensees, and Customers. Unlike in previous times, a government agency no longer "sets" tariffs. It is up to Licensees to propose tariff adjustments for review and approval by the ERA, within the guidelines of this tariff policy. In the future, tariffs will be determined from the "Bottom Up" (based on the costs of the various Licensees involved), not "Top Down" (final retail tariffs administratively determined and allocated back to Licensees in a non-transparent manner).

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1. BACKGROUND

This report addresses the Methodology to be used in establishing tariffs that the Energy Regulatory Authority (ERA) of Mongolia and its Staff can utilize as the regulatory process in Mongolia continues to advance and improve. The tariff process and methodologies must reflect the market structure and the realities of the Mongolian situation. The report will focus on basic tariff principles and the relevant provisions of Mongolian Law, build upon that foundation to recommend specific methodologies, and then address more advanced topics such as subsidies, incentives for market participants, quality of service, etc. that may be utilized in the near term or as the process continues to evolve in the future.

The goal of the Energy Sector Restructuring Project (ESRP) is to assist with the implementation of the new Energy Law aimed at restructuring the sector to shed unnecessary fuel, equipment, and labor cost burdens, creating efficient energy facilities and operations that yield a consistent and profitable contractual, regulatory, and industrial framework. This framework will attract investment to support new supply facilities to meet energy demand at least cost while improving supply, reliability, and efficiency. The activities to be undertaken by the Project include:

- Restructuring the vertically integrated utility (EA) - unbundling into state corporations;
- Establishment of an Energy Regulatory Authority;
- Setting up a licensing regime to ensure that commercial and regulatory commitments are honored and consumer protection is provided;
- Development of network operations and access rules;
- Development of cost-of-service-based tariffs to allow for recovery of costs and to provide for new investments in the future, including the deregulation of fuel prices and contract prices between eligible consumers and non-regulated suppliers;
- Development of a system of competition in generation and perhaps in retail (supply) if economically warranted;
- Commercialization of the sector entities and preparation for privatization; and
- Privatization of the State owned commercialized companies with level and timing determined by Government policy.

Accomplishment of these activities is dependent on actions by the Government of Mongolia. The USAID program will provide the essential framework and supportive technical assistance necessary for the GOM to achieve the program results.

The “Law of Mongolia on Energy” became effective April 15, 2001. It stipulated the restructuring of the vertically integrated electricity and heat sector, then part of the Energy Authority under the Ministry of Infrastructure. During the second half of 2001, the sector was unbundled in accordance with the law. The restructuring was accomplished by the creation of 18 new companies along the business lines of:

- Generation (Electricity and Heat)
- Transmission
- Dispatching
- Electricity Distribution

- Heat Distribution
- Regulated supply of energy

Those 18 new entities were spun off from the Energy Authority, each with their own corporate identities and financial structures. As far as tariffs are concerned, each Licensee must have tariffs in place to recover its costs and then Retail Tariffs for end-use Customers, based on the tariffs of the Licensees, must be developed. Each of the companies holds one or more licenses to operate in the newly restructured environment. The entities are regulated by the Energy Regulatory Authority (ERA), primarily utilizing the tools of licensing and tariff approval.

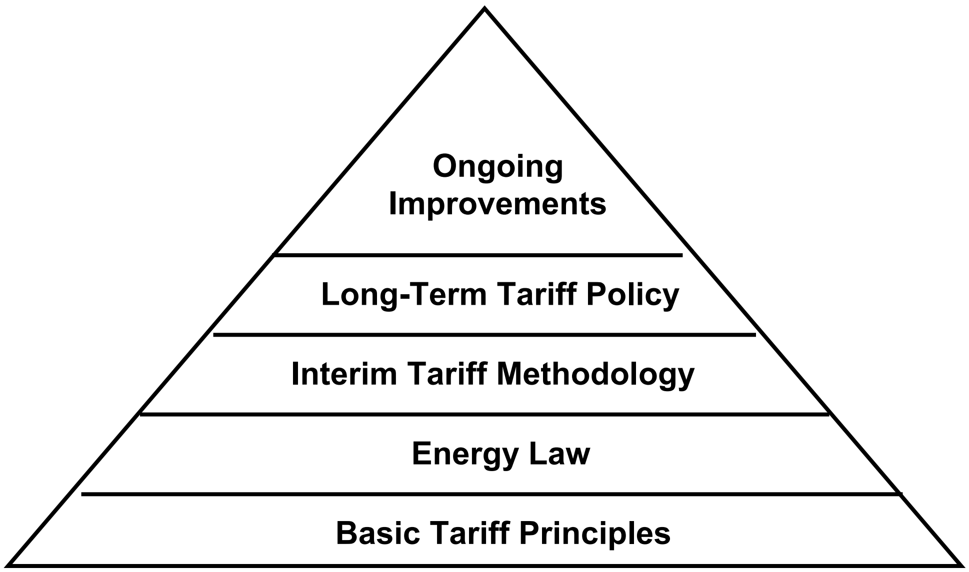
The Mongolian Power Sector has been progressing at a rapid pace as evidenced by the accomplishments to date:

- The Energy Law being passed in April 2001
- Establishment of the Energy Regulatory Authority (ERA) in June 2001
- Government Resolution #164 on Energy Sector Restructuring Issued in July 2001
- The unbundling of the sector into 18 corporate entities during the second half of 2001
- The issuance of temporary licenses in the fourth quarter of 2001
- Development of an Interim Tariff Methodology that was used to establish tariffs for all licensees in December 2001

Mongolia currently has a tariff situation that puts it far ahead of most developing countries. For the majority of the energy sector, the Central Electricity and Heat System, licensee and retail tariffs cover approximately all financial costs of the Licensees for providing electricity and heat, although cross subsidies between the electricity and heat functions and among individual customer classes exist. The task here is to build upon that solid foundation to develop the longer-term tariff methodology as depicted in Exhibit 1.1.

The Law of Mongolia on Energy gives the ERA the authority to develop a tariff methodology, however, it is important to realize that this is not “ERA’s Tariff Policy” alone. It is the Tariff Policy for the Energy Sector of Mongolia, and all the Stakeholders involved, including the Government, ERA, Licensees, and Customers. Unlike in previous times, a government agency no longer “sets” tariffs. It is up to Licensees to propose tariff adjustments for review and approval by the ERA, within the guidelines of this tariff policy. In the future, tariffs will be determined from the “Bottom Up” (based on the costs of the various Licensees involved), not “Top Down” (final retail tariffs administratively determined and allocated back to Licensees in a non-transparent manner).

Exhibit 1.1 Building Blocks of a Tariff Policy



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- Generators in the Central Electricity System
- Wholesale Market Pricing
- Transmission
- Distribution and Retail Electricity Supply
- Heat Distribution
- Isolated Systems

Once Licensee tariffs are developed, other tariff related issues must be addressed including Performance Based Regulation, Subsidies, Demand Side Management, and Tariffs for Low-Income Customers.

We then have all the tools in place to determine Retail Tariffs. Next we must focus on the Distribution/Retail Supply Licensees that are responsible for developing retail tariffs. A revenue requirement for serving retail customers must then be developed and allocated to customers using a Cost of Service methodology to assign costs to customer classes based on their energy usage characteristics, primarily the voltage at which they receive service. The next step is to use the Cost of Service information to design the actual tariffs.

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2. BASIC TARIFF PRINCIPLES

There are a wide variety of tariff policies and procedures in place around the world. Every country has a different market structure and the resulting pricing in each market tends to be unique. In some countries there are few laws and regulations dealing with the issue and the responsibility for establishing prices rests with government ministries that do not establish tariffs in a transparent manner, much less a commercial one. On the other hand, other countries have very sophisticated energy markets, requiting complex tariff structures. The Mongolian Power Sector has been progressing at a rapid pace as evidenced by:

- The Energy Law being passed in April 2001
- Establishment of the Energy Regulatory (ERA) in June 2001
- Government Resolution #164 on Energy Sector Restructuring Issued in July 2001
- The unbundling of the sector into 18 corporate entities during the second half of 2001
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As evidence that regulation can be applied in different ways, one only has to look at the United States to see that, although the basic legal framework is similar, each state and the federal government take a different approach. There is definitely no single approach to market structures or the resulting methods used to price the output of those markets. There are some basic principles, however, which most Economists and power sector specialists can agree on, although those principles can be applied in various ways. This chapter attempts to summarize the principles that can be thought of as “Guiding Principles” for the establishment of a tariff policy and the resulting methodologies.

The regulation of industries that are critical to the economic and social development of a country has many dimensions and the resulting pricing of the output has far reaching consequences for all members of society. Having a “market” for electricity that is efficient should be an ultimate objective for all countries, regardless of whether it is a public or private market structure. If there is effective competition in a market, the role of the regulator is a rather simple one, to monitor the market and insure that it continues to remain competitive. However, there is not perfect competition (from an economic point of view) in any country. The job of the regulator, therefore, is to intervene in the market to act as a proxy for competitive forces. The level of that intervention varies greatly depending on the market structure. The establishment of tariffs is not just a ‘Financial Task” that can be performed in a vacuum. Macroeconomic and microeconomic considerations come into play along with many social dimensions. Solid business management practices also need to be applied such as cost management and achieving a customer focus.

Economic considerations focus on the importance of having an efficient electric industry to contribute to the growth of the overall economy. Other industries depend on a supply of electric power to operate and grow. The electricity sector utilizes scarce natural and human resources and those should be effectively utilized. Pricing mechanisms must facilitate these economic objectives.

Financial dimensions include developing a pricing structure that will provide efficiently managed suppliers (Licensees) the opportunity to remain financially viable while at the same time offering customers a reasonable price. The job of the regulator is made much easier if the suppliers are utilizing solid business management principles to balance their multiple priorities of providing quality service and controlling costs. Regulators often have to provide incentives to suppliers to strike that balance.

Social considerations require a considerable amount of time and effort on the part of regulators. Protection of consumers is required in any market and especially in this one. Unbundling raises considerable concerns with respect to consumer protection, i.e. in the absence of a state owned vertically integrated utility, who will protect the consumer from monopolistic and/or unfair business practices? Commonly, this responsibility falls upon the regulator, as is the case in Mongolia; thus the ERA must prepare itself for this fundamental responsibility and gain credibility that it can provide adequate protection for consumers. Consumer rights including access to service, quality of service, and fair pricing are extremely important. Given the variety of customer classes with varying usage patterns, fair pricing requires much more than putting a single value on a kilowatt-hour. Social considerations focus heavily on those consumers requiring electricity to survive in their personal and work lives, but having limited income. Regulators must recognize that subsidies are a reality and the task is to make those subsidies transparent and effective with a logical funding source. Protection of the environment and the efficient use of electricity are social responsibilities with many dimensions, including pricing.

In order to lay the groundwork for the development of a tariff methodology, certain guiding principles or objectives should be followed. The approach to electricity pricing recognizes various objectives and criteria, some of which are not mutually consistent. The more important principles may be summarized as follows:

- Resources of the national economy must be allocated efficiently among the different sectors as well as within the power sector. This means that prices reflecting costs are to be used to indicate to the electricity consumers the economic cost of supplying their specific needs. This in turn should lead to efficiently matching supply and demand and to sending the correct price signals;

- Given that an adequate supply of electric service is critical to the development and growth of other sectors of the economy, proper pricing is necessary for overall economic growth;

- Costs should be allocated to consumers according to the burden they place on the system. In general, each class of customer should pay its appropriate share of the cost to provide service to it;

- The tariffs should generate sufficient revenues to ensure the financial viability of the Power Sector Licensees and to recover their justifiable costs. For power sectors operating on a commercial basis, investors expect to recover the full cost of providing service that includes: recovery of (a) all justifiable operating and maintenance costs, (b) the cost of facilities devoted to providing service, (c) taxes, and (d) the financial costs incurred to finance the investments in facilities used to provide service;

- The tariff structure should be simple and not become an administrative burden. It should facilitate metering and billing and allow the consumers to understand the basis for their cost of electricity;

- The tariffs may take into account macro economic and political requirements such as regional or special sector development, which may have to be "jump-started" or even supported on the longer run with subsidized power supply;

- A variety of tariffs are needed in order to match supplier cost structures with customer needs;

- As the unbundling and restructuring process is institutionalized, consideration may be given to performance based tariff ratemaking; i.e. tariffs which send the proper market signals to encourage efficiency of operations and reward utilities that achieve gains in operational (financial and technical) efficiency.

- Social considerations must be factored into the tariff process. Protection of consumer rights and fair pricing are obvious social factors, but other public policy objectives are also important. Environmental protection, low-income consumer needs, and energy efficiency are some of the areas that must be considered;

- If, for political or social reasons, it is decided that some customers should pay less than the cost to provide service to them (lifeline tariffs, for example), then the amount of that subsidy should be quantified. A transparent methodology must then be determined to either have other classes of customers or State or Local budgets pay for the subsidy. In the instance where tariffs are set below cost to subsidize poor customers, consumption limits must be determined and enforced to prevent abuse.

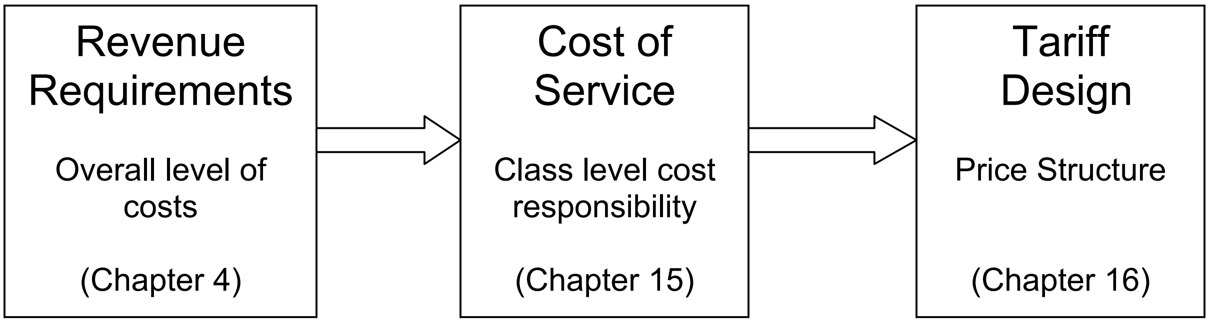
- Electricity tariffs are not the appropriate tool to use to solve problems in other industries, or to impose penalties and/or restrictions on utility operations. Prices should be based on the cost to serve a particular load profile. If other industries feel they need subsidies, then they should establish their own, hopefully transparent subsidy mechanism. If the government concurs that a subsidy is necessary to achieve its policy goals, then it should fund the subsidy;

- The costs of licensees pertaining to nonlicensed activities must be identified so they are not considered for tariff recovery;

- Costs should be separated into two categories, fixed and variable. Fixed costs are associated with facilities and are related to the demands (expressed in kW) placed on the system at the production, transmission, or distribution levels. Variable costs are related to output over a period of time and vary with kWh output. To the extent possible, tariffs should reflect these separate components in order to send the correct price signals to customers. This requires adequate metering devices.

Very often some of these criteria conflict with one another. Therefore, tradeoffs and compromises have to be made and this is where the regulator plays a critical role

The basic tariff development process will be presented as a three-step procedure as follows:



The chapters noted above deal with each of these steps individually.

3. LEGAL BASIS FOR TARIFFS IN MONGOLIA

3.1 BACKGROUND

In April 2001, the Ikh Hural passed the "Law of Mongolia on Energy" (referred to as the Energy Law). This law forms the basis for the structure and operation of the entire energy sector. The main provisions include:

- Establishment of the Regulatory Authority
- Establishment of Licensing for Sector Participants
- Broad Principles for Setting Tariffs
- Relationships Between Suppliers and Consumers

The tariff policy must be in accordance with the provisions of the Energy Law and, therefore, a review of the provisions dealing with tariffs and other related issues is in order.

3.2 PROVISIONS OF THE ENERGY LAW DEALING WITH TARIFFS

3.2.1 Definition of Tariffs

Article 3 of the law provides definitions of terms including:

> *3.1.8. "Tariffs" means prices approved by the Regulatory Authority and published. These may include any one or all of the following: producer prices, charges for dispatching, transmission, distribution and supply, as well as import prices;*

3.2.2 Duties and Powers of the Regulatory Authority

The Regulatory Authority is given a significant amount of authority. Its wide-ranging duties are specified in Article 8 as follows:

> *8.1. Duties of the Regulatory Authority shall be to regulate generation, transmission, distribution, dispatching, and supply of energy.*

Specific powers of the ERA are enumerated in Article 9. Those dealing with tariffs are as follows:

> *9.1. The Regulatory Authority shall have the following full powers:*
>
> > *9.1.4. To develop methodology to determine tariffs, define the structure of tariffs; to review, approve, inspect and publish tariffs of licensees;*
> >
> > *9.1.5. To establish a pricing and tariff system that enables supply of energy at the lowest possible cost and allows an adequate rate of return;*

3.2.3 Obligations of Licensees

In order to carry out its oversight and tariff setting responsibilities, a regulator must have access to accurate information from the regulated entities (Licensees). Article 25 enumerates the obligations of Licensees including:

25.1. Licensees shall have the following obligations:

25.1.3. To keep financial and accounting records for each licensed activity, separately from records of activities not specified in the license.

25.1.4. To submit its audited financial statements to the licensor every year.

25.1.8. To provide accurate information required by the licensor necessary to evaluate technical and economic performance of the licensee, on a timely basis.

3.2.4 Principles for Setting Tariffs

In the Energy Law, the Ikh Hural did not codify precise formulas that must be used to determine tariffs. This is a positive aspect of the law since economic and market conditions can be expected to change over time. The Regulator, in this case ERA, must have the ability to react to changing circumstances to regulate the industry in an effective manner. In Chapter 4, "Prices and Tariffs", The Energy Law does, however, provide some guiding principles. Article 26, Principles for Setting Tariffs," reads as follows:

26.1. Tariffs shall be determined separately for each licensed activity including generation, transmission, distribution, dispatching and supply of electricity and heat.

26.2. The following principles shall be observed in determining tariffs:

26.2.1. tariffs should be based on real costs of operations;

26.2.2. costs should be allocated to different consumer classes according to their requirements on electricity and heat supply;

26.2.3. tariffs should enable regulation of energy consumption;

26.2.4. tariffs should ensure price stability;

26.2.5. tariffs should ensure that revenues of licensees are sufficient to support their financial viability;

26.2.6. the tariff structure for electricity and heat should be clear and understandable for consumers;

26.2.7. the least-cost principle should be followed while tariffs should be sufficient to enable compliance with the requirements of technical and technological safety in energy generation, transmission, distribution, supply and dispatching;

26.2.8. the cost should be determined based on prior years' performance. However, depreciation of future investments or renewals should not be incorporated in the cost.

26.3. The Regulatory Authority shall be responsible for assessing justification and accuracy of cost estimations by licensees. It shall return the cost estimates to the *licensee for a revision in case the estimates are not adequate. The Regulatory Authority shall not itself complete licensee's estimates by giving suggestions or making estimates on behalf of the licensee.*

26.4. The Regulatory Authority shall develop and publish tariff determination methodology and procedures for review and examination of tariffs.

Article 27, "Tariffs and Contract Prices" provides additional guidance:

27.1. The Regulatory Authority and Regulatory Boards of aimags and the capital city shall review tariffs and terms of services provided by suppliers annually, and may review them semi-annually upon requests of suppliers.

27.2. Consumers shall pay for regulated supply in accordance with published tariffs and for unregulated supply in accordance with contract prices.

27.3. The Regulatory Authority shall determine consumers eligible to receive unregulated supply on the basis of their electricity and heat load. These consumers have the right to choose either regulated or unregulated supply.

27.4. A holder of a regulated supply license shall submit any proposals for change in tariffs together with an itemized list of costs to the Regulatory Authority.

27.5. The Regulatory Authority shall notify consumers or publish in mass media information about changes in energy tariffs no later than 15 days prior to the date when these changes become effective.

27.6. Tariffs and contract prices may differ for certain groups of consumers depending on the following factors of energy supply in addition other factors:

27.6.1. Maximum load requested and consumption specified in the contract;
27.6.2. Load factor or pattern of load;
27.6.3. Ability of the consumer to manage its load or willingness to accept interruptions in the supply;
27.6.4.Geographical area served by the supplier;
27.6.5. Duration of the contract;
27.6.6. Other factors.

3.3 MOVING FORWARD

As indicated in Chapter 1, the Energy Law is one of the building blocks for a tariff policy. The tariff methodologies proposed in the following chapters of this report must, therefore, be in accordance with the guiding principles of the law.

4. DETERMINING REVENUE REQUIREMENTS

4.1 INTRODUCTION

The first step in the overall tariff process is the determination of "Revenue Requirements", the overall level of costs to be recovered by the Licensee. In a completely competitive market situation, a regulator or government agency need only concern itself with monitoring the market and making sure that it remains competitive. The market determines prices and it is up to market participants to control their costs in order to remain financially viable. As we move away from perfect competition, there is a constant need to prevent monopoly power from negatively affecting the consumers. In the case of cost based regulation, it is up to the regulator to determine which costs of the supplier are to be recovered in tariffs.

Remembering that one of the responsibilities of a regulator is to provide a framework in which efficient suppliers have the opportunity to achieve financial stability, the ERA must determine the basic cost recovery criteria to be applied in the process. Financial criteria utilized should become increasingly more commercially oriented as the energy sector moves to a commercial environment. This requires earning a reasonable return on invested capital in addition to recovery of expenses.

The ERA currently has an "Interim Tariff Methodology" that has been used since December 2001. The Revenue Requirement Methodology discussed herein will build upon that solid foundation and focus on improving several aspects of it.

4.2 COMPONENTS OF THE REVENUE REQUIREMENT

In the case of cost-based regulation, there are specific components of a revenue requirement that must be considered to provide a financially viable environment in which regulated entities participate. In some cases, the regulator may decide that certain components (depreciation, interest on certain loans, return on equity, etc.) will not be included in tariffs or be included at reduced levels. It is important that the regulator be aware of each component and its estimated value in order to make informed decisions. The following components will be discussed in detail:

- Operation and Maintenance costs
- Depreciation
- Taxes
- Return on Investment (Financial Charges)

4.2.1 Definitions of Cost

The current discussion of "Costs" is focused on Financial Costs, the cost elements that would be recorded on an entity's financial statements. A revenue requirement can utilize historical financial cost or forecasted financial cost. The preferred method is to forecast the costs for a future period (generally the following year) when the resulting tariffs will be in place. That practice has been followed with the Interim Tariff Methodology.

A revenue requirement could also be based on "Marginal Cost", the cost required to supply an incremental amount of the product or service. We could, therefore, define "Cost" as Marginal Cost. Economic principles state that, in a competitive market, efficient allocation of resources is accomplished when price is equal to the marginal cost of supply, with the intent of sending the correct price signals to the market and resulting in the most efficient allocation of resources. Marginal Cost, as compared to Financial Cost is forward looking and focused on how much will it cost to provide the next increment of capacity to serve the demand (KW) or how much will it cost to generate the next kWh. Although it is based on sound economic principles, marginal cost is used to a very limited extent in actual practice. Furthermore, in the case of Mongolia, it is definitely not appropriate at this time since the Mongolian power system is far from a competitive one and since its strict application would significantly increase retail tariffs. In addition, the Energy Law basically forbids the use of marginal costs (Section 26.2.8. states: "the cost should be determined based on prior years' performance. However, depreciation of future investments or renewals should not be incorporated in the cost"). Therefore, marginal cost tariffs will not be appropriate for the energy sector of Mongolia for the foreseeable future (at least within the next 10 years).

4.2.2 Financial and Cost Accounting Issues

To put the issue of revenue requirements in the context of the Mongolian Power Sector Licensees, one must consider the accounting practices used in the country. The Licensees follow accounting procedures that conform in many respects to International Accounting Standards (IAS), however, they cannot be considered to be in strict compliance with IAS. Licensees use a double entry bookkeeping system, the standard subsidiary ledgers (accounts payable, accounts receivable, inventories, expenses, etc.) are kept primarily on an accrual basis, and statements can be produced that follow the basic IAS formats. The Licensees actually have a reasonable, workable accounting system as compared with energy entities in many developing countries, showing that significant progress has been made. There are several limitations to the financial statements that the reader should be aware of, however, including:

- Although "Audits" are performed by local accountants, they are not in accordance with IAS.
- There is no disclosure to enable the reader to obtain a good understanding of the statements. The reader does not know, for example, the basic accounting principles used to produce the statements or the reasons for major deviations in balances. Adequate disclosure is a critical element of IAS compliance.
- There is not always consistency in presentation
- IAS Accounting policies are not followed in the following areas:
    - There is no Bad Debt Expense recorded on the income statement and no Allowance for Bad Debt on the balance sheet, resulting in an understatement of expense and an overvaluation of Accounts Receivable
    - Fixed Assets are not properly valued since the Mongolian power sector has historically capitalized significant maintenance costs as opposed to charging them to expense. This has the effect of understating maintenance expense and overstating the value of fixed assets.

- Depreciation practices do not necessarily correspond to IAS, since the lives used for fixed assets often are based on tax lives that are significantly shorter than the expected life of the actual equipment or are based on Government of Mongolia "Guidelines" that may not be reasonable.
- International Loan Liabilities are not recorded until the projects are completed, resulting in an understatement of Construction Work in Progress and an understatement of Long-Term Debt.
- Interest expense is often not recorded until it has been paid, although the on-lending agreements between the Companies and the GOM call for interest to be paid. This results in an understatement of expenses and interest payable.

In addition, Mongolian companies follow the practice, common in ex-Socialist countries, of recording certain expenses (primarily social expenses related to employees) as being "Deductions from Profit" as opposed to operating expenses. This is done since most companies follow tax formats (as opposed to IAS formats) when publishing their financial statements and those expenses are not deductible for tax purposes. The reader may be familiar with a similar practice of regulated utilities in the US recording certain expenses "Below the Line" if they were determined by the regulator to be unrelated to utility operations or otherwise not recoverable through regulated tariffs.

The above discussion highlights the importance of establishing uniform accounting and reporting guidelines for Licensees to follow in the energy regulatory context. The Licensees, of course, are subject to various accounting and reporting requirements of the tax authorities and other governmental agencies, but when dealing with the ERA, information should be in format that is useful for monitoring performance and setting tariffs. Chapters 17 and 18 deal with this issue of providing information to the ERA.

From the point of view of a regulator, the important thing is to make sure that Licensees are consistent in their application of accounting principles. For example, there is a tendency in some years for companies to capitalize costs (as opposed to charging them to current expense) in order to improve current year operating results. This, of course, increases depreciation expense in future years. In other years, they may charge similar costs to current expense.

In some countries, regulators perform "Compliance Audits" to make sure that licensees consistently follow the regulatory accounting requirements. Since the Mongolian power sector is so small, however, the regulatory accounting requirements are very simplified (primarily related to the reporting issues discussed in Chapters 17 and 18). Also, with the limited resources of ERA, it is not practical at this time to perform compliance audits on the various licensees. At a minimum, however, the ERA can require licensees submitting tariff applications to certify that they are consistently applying accounting principles, especially in areas related to fixed assets. A periodic review of sample transactions would allow the ERA to have some confidence that accounting is consistent.

In the future, the ERA may want to establish a "Uniform System of Accounts" for licensees and implement a compliance audit program. However, in the near term there are higher priority tasks.

4.2.3 Operation and Maintenance Costs

Licensees incur costs in the course of operating their business and maintaining their plant and equipment. The costs of the entity must first be categorized to identify those pertaining to licensed activities and all other costs. This is very important for entities that are involved in multiple lines of business. Accounting systems must be able to specifically identify as many costs as possible and assign them to the licensed activity (or multiple license activities in some cases) or to nonlicensed activities. In the case of costs that cannot be directly assigned (such as shared facilities, administrative activities, capital costs), a rational, consistent method must be used to allocate them to the licensed and non-licensed activities of the business. In the case of electric and heat licensees, operation and maintenance costs generally include:

- Fuel for generation
- Power or heat purchases
- Salary costs
- Other employee related costs (benefits, taxes)
- Repairs and maintenance
- Administrative and General
- Meter reading
- Billing
- Collection expense
- Bad debt expense

The Regulator must review the costs for reasonableness and the licensee must be prepared to demonstrate that costs are being controlled and value is received for the amount spent. On the other hand, the Regulator should not be short sighted and only worry about minimizing costs since power systems require significant maintenance in order to be able to provide a reasonable level of reliability. In fact, prudent maintenance should be encouraged and, if service levels improve, rewards could be given in future periods. Major cost components such as fuel should receive a high level of scrutiny and related activities such as loss reduction programs should be reviewed since they will lead to decreased power requirements. The regulator must not overlook smaller cost elements, since they may increase needlessly if they are not monitored. It must be emphasized that it is not the regulator's responsibility to dictate to the licensee how to run its business or to second-guess decisions made in the everyday operation of the business. The regulator, however, does have the responsibility to review the costs in relation to the service provided and to assess if customers are receiving value. Regulators in various jurisdictions would agree that the determination of the prudence of expenditures requires a significant amount of judgment in addition to expertise in the industry and familiarity with utility best practices. They refer to the "Reasonable and Prudent" and "Used & Useful" criteria, among others.

Collection of accounts receivable is a problem throughout Mongolia; however, the ERA has not yet included an allowance for bad debts in the tariffs. In the future an allowance for bad debt should be included in the wholesale and retail tariffs to recognize that virtually no suppliers collect 100% of the amounts billed to customers. In accordance with International Accounting Standards, bad debt expense should be recorded to recognize that 100% of the revenue recorded in a particular period will not be collected and also to prevent the Accounts Receivable balance from being overstated. A recommendation has been made to the ERA for inclusion of Bad Debt expense in tariffs, along with a methodology to implement it. Appendix E contains a document that was prepared for the State Property Committee outlining the issues related to bad debt expense, the recommendation made for inclusion of bad debt expense in tariffs, and the accounting issues involved. The reader may want to review Appendix E for more information on this topic.

4.2.4 Depreciation

Licensees must recover the investment they make in plant and equipment and this is generally accomplished by incorporating an allowance for depreciation in the tariff. Investors in a private utility consider this the return OF their investment. In the case of entities (Public or Private) that finance plant and equipment investments with debt securities, they count on recovering depreciation in tariffs in order to repay the principle on the debt (interest is recovered separately in the form of a return ON investment). Equity investors expect the entity to recover depreciation costs in tariffs to maintain the value of the entity in which they invested.

In the case of state owned enterprises, the government should be interested in recovery of depreciation in tariffs since public funds were used to acquire the plant and equipment. If the licensee does not realize cost recovery of depreciation, the "value" of the Government's investment will deteriorate and if it is decided in the future to privatize the entity, it will be worth less. Also, recovery of depreciation, a non-cash charge to earnings, provides funds for investment in new fixed assets. If the government decides, for social or other reasons, to set tariffs at a low level and forego recovery of depreciation, they should realize that they are giving an indirect subsidy to customers.

Depreciation should be recovered in tariffs over the remaining useful life of the related fixed assets. Depreciation practices in Mongolia do not necessarily correspond to IAS, since the lives used for fixed assets often are based on tax lives that are significantly shorter than the expected life of the actual equipment or are based on Government of Mongolia "Guidelines" that may not be reasonable. The ERA should encourage Licensees to utilize depreciation rates by type of equipment that reflect the remaining useful life of the equipment. Attachment D contains a presentation that addresses the specifics of depreciation in the context of a regulated entity.

The issue of fixed asset revaluation has been raised by several Licensees. As discussed in the June 9, 2003 meeting on the establishment of the tariff methodology, the revaluation of assets is not appropriate at this time. Revaluation of the assets of a State Owned Enterprise (such as any of the current Licensees) increases the cost of the fixed assets, and therefore, depreciation and the revenue requirement to be recovered in tariffs. The customers, therefore, pay higher tariffs while the government shows a higher equity interest in the Companies. Since tariff increases are so politically unpopular, the Mongolian Consumers would be better served by restructuring the tariffs in line with cost of service principles (as discussed herein) using the current fixed asset values. In the future, once the tariffs are rationalized, fine-tuning such as asset revaluation can take place. Of course, for the older assets (other than those financed with international soft loans) that were constructed and financed with the old artificial currencies, asset valuation is very difficult, costly, and contentious. As Licensees become privatized, the assets will be revalued based on the purchase price paid.

The primary reason that Licensees want to revalue fixed assets is to increase depreciation expense and produce additional cash flow. Since Licensees have very limited access to commercial financing, cash flow is severely limited, resulting in lack of investment funds for projects to reduce technical and commercial losses and other such worthwhile projects. The

Tariff Methodology cannot, by itself, solve the cash flow shortage of the Distribution Licensees. It can, however, provide reasonable cost recovery mechanisms for capital investments (depreciation and return on investment) to encourage investors (including commercial bankers) to provide funds to the sector.

4.2.5 Taxes

Taxes are costs to an entity just the same as materials and wages. They generally include Property Taxes, Value Added Taxes, Employment Taxes, and Income Taxes. The tariffs must incorporate an allowance for all taxes related to the licensed activity. In some instances, estimates and allocations may be involved and the Energy Regulatory Authority should review these for reasonableness and consistency in application.

4.2.6 Return on Investment (Financial Charges)

Investors commit their funds to business ventures in anticipation of earning a return at least equal to what the next best investment alternative would offer. The anticipated risk is inherent in the expected return. Businesses utilize investor funds to make investments in plant and equipment in anticipation of earning a return on that investment. Investor funds consist of:

- Short-term loans
- Long-Term Loans (mortgage bonds, debentures, term loans, International soft loans)
- Equity

In the case of an entity involved only in a single licensed activity, the return on investment for the three components above can be incorporated in the revenue requirement in a relatively straightforward manner. In that case, the cost of each component can be computed as follows:

- The cost of short-term debt would be recorded in the financial statements in the case of a historical test period. For a forecasted period, the estimated principal amount outstanding (on an annual, quarterly, or monthly basis) would be multiplied by the effective cost of short-term debt for the period, including consideration of any fees or compensating balances.

- The cost of long-term debt would be based on the effective rate of each instrument, incorporating the effects of any premiums or discounts as well as the expense of issuance. In the case of international loans, the interest rate specified in the on-lending agreement should be used. A review of the on-lending agreements recently developed by the Ministry of Finance and Economy indicates that the debt repayment schedules call for the individual entities to repay the loans in the currency in which the loan was made to the Government of Mongolia. This presents a potentially significant risk to small entities such as the power sector licensees. Prudent business practice would dictate that the entity hedge the currency risk, however, the entities have neither the expertise nor the financial resources to do so. Only the Government of Mongolia can effectively manage the currency risk. It has, therefore, been recommended that the on-lending agreements be rewritten to reflect payment in Togrog.

- The cost of equity is determined by applying a cost rate to the average amount of equity outstanding for the period. The question is what cost rate to apply and that issue is discussed in Section 4.2.7.

Determining return on investment, especially in the case of entities involved in businesses other than licensed activities or for entities involved in several licensed activities (for which costs must be separately identified), becomes more complex. One common method used by regulators to determine return on investment is to compute the product of "Rate Base" and "Rate of Return".

Rate Base is the investment that the entity has made in order to provide the licensed service. It includes:

- Net Investment in Plant and Equipment computed as the cost of plant and equipment invested in the licensed activity, less the accumulated depreciation pertaining to that equipment
- A Working Capital Allowance; generally the difference between Current Assets and Current Liabilities (excluding Short-Term Debt), the principle components being:
    - Inventories (fuel, materials, supplies, consumables)
    - Accounts Receivable
    - Prepaid Expenses
    - Accounts Payable
    - Wages, taxes and other payables

The resulting "Rate Base" is the sum of net plant plus working capital allowance and is the investment upon which the licensee should be allowed to earn a reasonable return.

Determining the appropriate rate of return to allow a licensee the opportunity to earn is a very important aspect of a regulator's job. It is also one of the most difficult. In general, the appropriate rate of return is the "Cost of Capital" of the licensee. As with any other resource, capital has a cost.

Generally, cost of capital is computed as the weighted average cost to the entity of the debt and equity components in its capital structure (historical or forecasted) as follows:

Cost of Short-term Debt (STD) times the % of STD in the capital structure
+ Cost of Long-term Debt (LTD) times the % of LTD in the capital structure
+ Cost of Equity times the % of Equity in the capital Structure (see Section 4.2.7 for a discussion of the cost of equity)

Once the cost of the various components is determined, the cost of capital (or rate of return) calculation is made as shown in the table below with the resulting rate of return of 12.9%:

Component	**Amount**	**Percent of Total**	**Cost (%)**	**Weighted Cost (%)**
Long-Term Debt	90,000	50 %	12 %	6.00 %
Short-Term Debt	18,000	10 %	9 %	0.90 %
Equity	72,000	40 %	15 %	6.00 %
TOTALS	180,000	100 %		12.90 %

The 12.9% rate would then be applied to the rate base pertaining to the licensed activity in order to determine the Return on Investment component of the Revenue Requirement.

4.2.7 Return on Equity Issues

Determining the appropriate return on equity is a very important aspect of a regulator's job. It is also one of the most difficult and requires a significant amount of judgment. Entire books have been devoted to the topic of cost of capital, however, only a brief description will be given here. In general, the return on equity should be adequate to attract capital to the industry and its cost depends on many factors such as:

- Interest rates in general
- Investor expectations
- Country risk
- Industry risk
- Company Risk

In some countries, it is very difficult to determine what an appropriate return on equity would be, especially in industries not previously subject to capital market situations. Regulators may determine that social considerations dictate that, in order to keep tariffs low, State owned entities should not be allowed to include a return on equity in tariffs. This is a common practice in many countries. The government should recognize, however, that it has a “cost of funds” and if it is not recovering the cost of its power sector investment in tariffs, then it is providing an indirect subsidy to electricity customers.

The Interim Tariff Methodology calls for a return on equity for State Owned enterprises of up to 3%, however, the ERA has been using a rate close to zero in order to keep tariffs low, presumably at the urging of the Ikh Hural and the Government of Mongolia. The concept of a return on equity has, therefore, been established, a positive move. To progress and move toward a more commercial environment, the ERA should gradually allow higher returns on equity over a period of time (say 5 to 7 years). This will set the stage for a more commercial environment to which private investors will be attracted. Methods for determining return on equity could include:

- Utilizing the return on equity earned by utilities in developed countries and adding a risk premium for the additional risk of investing in Mongolia
- Utilizing the cost of long-term debt plus a risk premium to reflect that equity investments are more risky than investments in debt securities. Of course, since there is not an established market for debt securities in Mongolia at the present time, this method cannot be utilized at this time.
- Once a viable equity market is operational in Mongolia, the Capital Asset Pricing Model (CAPM) can be used to estimate the return on equity. This model is based on the assumption that the return on a particular company’s stock is equal to the risk free borrowing rate plus a risk premium (equal to the difference between the overall stock market returns times Beta, a statistical measure of the movements of the individual stock compared to the overall market movements).

When private investors enter the electricity sector, the ERA should require them to undertake a study to support and recommend an appropriate return on equity. The ERA must make it clear to potential investors that it is committed to tariff structures that will allow licensees to earn reasonable returns on equity (although not necessarily guarantee those returns).

As discussed in Section 4.2.9, the Return on Equity should include a component of at least 3% to cover the Social Costs of the Licensees.

To summarize the Revenue Requirement issue, the regulator must review and analyze the tariff submission of the Licensee and determine the cost to be allowed for each of the components including:

- Operating and Maintenance cost
- Depreciation
- Taxes
- Return on Investment

From the point of view of the licensee, if it agrees with the components included in the revenue requirement and if the cost of each component is reasonably established, then the licensee has the opportunity (but not a guarantee) to meet its objectives, assuming it can manage its costs to the levels included in tariffs. If the management team of the entity can take actions to reduce costs, the entity can exceed the target (achieve higher earnings). Examples may include:

- Reduction of technical or commercial losses
- Reduction of station use at generating facilities
- More efficient utilization of personnel (productivity)

Caution must be exercised, however, to prevent the deferral of necessary maintenance of facilities. In fact, better maintenance practices can result in lower costs in the future and improved service levels.

Regulators must also realize that, in the case of State Owned licensees, the portion of the revenue requirement that is not collected from customers must be recovered from the government in the form of a subsidy. That subsidy could be a direct one in the form of cash transfers to the entity, or an indirect one in the form of deterioration in the value of the entity to its owner (the State).

4.2.8 Issues Related to International Loans

As discussed in Section 4.2.6, the on-lending agreements recently developed by the Ministry of Finance and Economy call for the individual entities to repay the loans in the currency in which the loan was made to the Government of Mongolia. This presents a potentially significant risk to small entities such as the power sector licensees. Prudent business practice would dictate that the entity hedge the currency risk, however, the individual licensees have neither the expertise nor the financial resources to do so. Only the Government of Mongolia can effectively manage the currency risk. It has, therefore, been recommended that the on-lending agreements be rewritten to reflect payment in Togrog.

Although that recommendation was initially made to the Government of Mongolia in November 2002 and has since been reaffirmed several times, no response to the recommendation was received and no action has been taken. Although there has not been a significant fluctuation in the exchange rate between the Togrog and the various currencies in which the loans are denominated (Yen, Marks, SDRs, etc.) there has been some fluctuation and several Licensees have raised the issue of what would happen in the event of a major depreciation in the value of the Togrog. If the Government of Mongolia continues to insist that the energy sector companies must expose themselves to foreign exchange risk, then the tariff methodology must allow for immediate pass-through to customers of the foreign exchange losses (relating to both principle and interest). This, of course, passes the risk directly to the electricity and heat customers.

Another issue related to international loans has to do with the tax treatment of interest payments. Mongolian tax law allows taxpayers to deduct interest on loans from taxable income, a treatment that is common practice in many countries. If, however, the interest is not actually PAID, then the deduction is disallowed. Such treatment is not unreasonable. In effect, it treats interest payments on a cash basis, as opposed to an accrual basis. Of course, in the case of Licensees, since interest expense is included in tariffs, there is no reason that Licensees should not pay the interest. If Licensees are using the cash flow from interest for other purposes, then the ERA should utilize its regulatory authority to reprimand licensees for mismanaging their finances.

4.2.9 Social Costs

Mongolian Accounting and Tax practices define certain expenses as “Social Costs” and prescribe unique accounting and tax treatment for them. This is actually a carryover from the old socialist accounting and tax methodologies, still in use in some countries. Social Costs primarily relate to certain benefits to employees and include such items as:

- Subsidies for meals
- Subsidies for transportation costs
- Subsidies for heating fuels

For accounting purposes, these costs are recorded as “Non-Operating Expenses” and for tax purposes they are not allowed as a deduction. The rational, a carryover from the old Socialist system, was that such costs were to be paid out of “Profits”.

Since these costs would normally be considered fringe benefits or additional employee compensation, it would be logical to include them along with operating expenses in the determination of the revenue requirement. The ERA, however, does not want the Licensees to have problems with the tax authority. Therefore, since the tax regulations assume that Social Costs are paid from “Profits”, which equate to “Return on Equity” in modern financial terms, then the ERA should allow all licensees to have a component in return on equity to cover these costs. A review of the Social Costs of licensees in the Central Energy System indicates that, on average, annual social costs are 1.9% of equity. Since social costs are not deductible for taxes, the revenue requirement to recover them would require a 3% component in return on equity (1.9% divided by 1 minus the tax rate of 40% approximately equals 3%).

In the longer term, the Licensees may decide to discontinue these subsidies to employees (which are not tax deductible) and instead pay slightly higher salaries (which are tax deductible). At that time, ERA may want to revise the above treatment. At the current time, however, it is recommended that return on equity be set at least at 3% to cover the Social Costs.

4.3 SAMPLE REVENUE REQUIREMENT CALCULATIONS

To put the concept of revenue requirement in more concrete terms, the reader is referred to the following example.

Assume that the Licensee presents the following financial statements (with associated backup materials) as a forecast of the future 12-month period as shown in Exhibit 4.1.

Exhibit 4.1 Projected Financial Statements

BALANCE SHEET
(millions Tg)

Assets		
Current Assets		
Cash	100	
Fuel Inventory	300	
Spare Parts	200	
Accounts Receivable	700	
Total Current Assets		1,300
Fixed Assets		
Cost	7,000	
Accumulated Depreciation	2,300	
Net Fixed Assets		4,700
TOTAL ASSETS		6,000
Liabilities and Equity		
Current Liabilities		
Accounts Payable	800	
Salaries Payable	150	
Taxes Payable	50	
Short-Term Debt (10%)	200	
Total Current Liabilities		1,200
Long-Term Debt (6%)		3,000
Equity		1,800
TOTAL LIABILITIES AND EQUITY		6,000

INCOME STATEMENT
(millions Tg)

Revenue (Current Tariffs)		
Electricity	1,900	
Heat	600	
TOTAL REVENUE		2,500
Operating Expenses		
Fuel	1,100	
Salaries and related costs	550	
Depreciation	400	
Current Maintenance	200	
Other Operating Expenses	110	
TOTAL OPERATING EXPENSES		2,360
Non-Operating Expenses		
Short-Term Interest Expense	20	
Long-Term Interest Expense	180	
Taxes	30	
		230
NET INCOME		(90)

Exhibit 4.1 shows that the current tariffs produce a negative net income of 90 million Tg, given the expected expenses for the period. In addition, the Licensee tariff application included a proposed Cost of Capital of 9.4% consisting of:

- Cost of Long-Term Debt of 6%
- Cost of Short-Term Debt of 10%
- Cost of Equity of 15%

This cost of capital applied to the projected Investment (Rate Base) results in a Return on Investment of 470 million Tg. The calculations are shown in Exhibit 4.2

Exhibit 4.2 Return on Investment

RETURN ON INVESTMENT:				
Investment:				
Fixed Assets			7,000	
Accumulated Depreciation			(2,300)	
Working Capital				
Current Assets			1,300	
Current Liabilities			(1,200)	
Short-Term Debt			200	
Net Investment				5,000
Cost of Capital:				
	Amount	Percent	Cost (%)	Weighted Cost
Long Term Debt	3,000	60%	6%	3.6%
Short-Term Debt	200	4%	10%	0.4%
Equity	1,800	36%	15%	5.4%
TOTALS	5,000	100%		9.4%
Return on Investment:				
Investment (Rate Base)				5,000
Rate of Return				9.4%
Return on Investment				470

The information in Exhibits 4.1 and 4.2 provides us with the specific amounts needed to calculate the revenue requirement of 2,860,000,000 Tg as shown in Exhibit 4.3.

Exhibit 4.3 Revenue Requirement

	REVENUE REQUIREMENT (millions Tg)			
I.	**Operation and Maintenance Expense**			
	Fuel	1,100		
	Salaries and related costs	550		
	Current Maintenance	200		
	Other Operating Expenses	110		
			1,960	
II.	**Depreciation**		400	
III.	**Taxes**		30	
!V.	**Return on Investment**		470	
	TOTAL REVENUE REQUIREMENT		2,860	
	Revenue at Current Tariffs		2,500	
	Required overall Tariff Increase		360	14.4%

As shown in Exhibit 4.3, in order to recover the total revenue requirement, a tariff increase of 360 million Tg is required[1]. The resulting net income would be 270 million Tg (-90+360) and, based on Equity of 1.8 billion Tg, the Return on Equity would be 15% (1.8 billion times 15% = 270 million). The reader can thereby see how the revenue requirement and the financial statements are related.

In subsequent chapters dealing with the determination of tariffs for the various categories of Licensees, a similar format will be used.

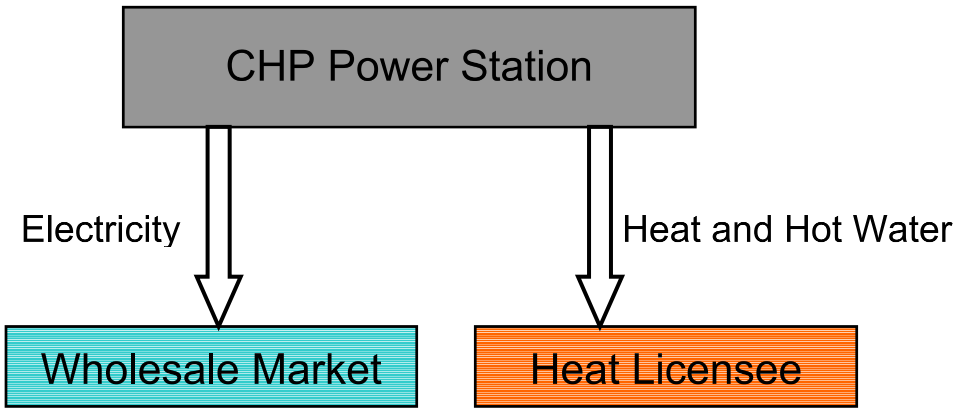
[1] This simplified example assumes no additional income taxes. If the Licensee was subject to an income tax rate of 30%, for example, the tariff increase would have to be 514 million Tg (360/(1-.3))

5. TARIFF METHODOLOGY FOR GENERATION LICENSEES IN THE CES

5.1 THE GENERATION MARKET STRUCTURE

5.1.1 Introduction

The Generation Licensees in the Central Electricity System (CES) operate Combined Heat and Power (CHP) Stations that produce two "Products" that are sold in different markets.



The electrical output is sold to the Wholesale Market (the Single Buyer) based on a Power Purchase Agreement between the power station and the Single Buyer. The pricing is subject to the approval of the ERA. At the present time, the electricity pricing is based on a single tariff per kWh for each power station based on its costs (including a subsidy for heat). The Government of Mongolia and the ERA have committed to revising this arrangement and having two-part generator tariffs for electricity. An Availability component will be utilized to allow the Licensee to recover fixed costs and an Energy component will provide recovery of the variable costs.

Heat output is sold to the local Heat Distribution Licensee based on a tariff approved by ERA for each power station based on its costs, net of a subsidy that is recovered in the electricity tariff.

5.1.2 The Electricity Market and Efficient Pricing

In the fourth quarter of 2002, a new Single Buyer Market structure was implemented in the CES with the 5 power stations selling all their electric output to a wholesale market. In general, a Single Buyer Market structure is the most appropriate for the system at this time. Since there is very little opportunity for effective competition in the system, a competitive power pooling arrangement cannot be implemented. A bilateral contract market is not appropriate since the purchasers of the output are almost entirely State Owned (large entities and distribution/supply companies), as are the sellers. At best, the commonly owned companies would be negotiating with themselves and, in the worst case; favorable contracts would be negotiated with certain entities and leave remaining customers with higher prices.

The current operation of the market, however, is not optimal. Such a market requires a set of Market Rules to specifically define the relationships between the parties (generators, the dispatcher, and the Single Buyer) in order to operate efficiently and economically. The primary ingredient that is lacking is the concept of economic, or Merit Order, dispatch. The Dispatch Licensee does not have specific criteria in place (including the marginal cost of generation for each power station) to optimize system economics. Less efficient power stations are dispatched to allow them to recover their fixed costs in order to remain financially viable. The tariff structure proposed herein aims to overcome that problem by allowing all power stations to recover their fixed costs based on their availability to generate and to leave the decision of the most economic mix of generation (and imported power) up to the Dispatch Licensee in real time.

The Central Electricity System is quite unique in that all power stations are combined heat and power stations and, probably more than any other power system in the world, dispatched based primarily on heat load. With no new sources of generation currently being developed, all existing generation is needed during the winter months. The traditional "Competitive" concept used in highly developed markets of driving out high cost suppliers is not appropriate in Mongolia at the present time. To substitute for competition and utilize the scarce resources of Mongolia (facilities and fuel) most efficiently, the market operation and tariff methodologies proposed herein are recommended. Additional technical assistance will be needed in the areas of developing specific Market Rules and Power Purchase Agreements in order to add structure to the system.

There are relatively limited opportunities for economic dispatch of the system, especially in winter, due to the fact that power stations have "Technical Minimum" amounts of electricity, defined as the amount of electricity that is generated due to the required heat (and hot water) output at a particular time. This results in the Dispatcher only being able to economically dispatch approximately 40% of the electric load on an economic basis in the winter and approximately 75% in the summer. This still leaves sufficient opportunity to economically utilize the scarce fuel resources, thereby satisfying economic criteria and one of the basic tariff principles discussed in Chapter 2.

The recommended procedures would provide for each Generator to sell its output to the Single Buyer based on a Power Purchase Agreement containing technical and commercial terms as well as a two-part tariff (approved by the ERA) with the following components:

- Availability Component – consisting of the fixed costs of the power station and expressed as Tg per available KW of capacity per day
- Energy component – consisting of the variable costs of the power station (primarily fuel) and expressed as Tg per kWh delivered to the market

The generator would receive its availability payment based on the number of KW it makes available to the Dispatcher that day – regardless of the amount of energy it generates. The intent is to compensate the generator for having available capacity (giving the Dispatcher flexibility), but to make the generator indifferent as to the level at which it generates.

For every kWh generated, the generator would receive the Energy Component of the tariff, thereby providing compensation for the variable cost of generating that energy. In the event that fuel costs increase from the base level included in the energy charge due to (1) price increases from the mines, (2) railroad tariff increases, or (3) the delivered price of mazut, a Fuel Adjustment Mechanism is recommended to compensate for the unanticipated changes.

The incentives inherent in such a system include having the power station available as much as possible and the reduction of variable costs by efficiently operating and maintaining the plant, allowing the generator to earn additional revenue and profits.

In order to achieve least cost in the CES, the dispatcher should make the decision as to the level of generation from each power station – given the significant constraints of heat required in this system as well as the normal load balancing or other constraints. Within those constraints, the Dispatcher would enforce merit order dispatch based on marginal cost.

A generator receives the availability payment for the day if it declares itself as being available. The amount is based on the fixed costs of the power station and the assumed availability factor. Least cost overall is achieved if the unit is available as much as possible, given prudent maintenance practices. The ERA must review the fixed costs (depreciation, interest, and fixed O&M) being proposed for prudence. The information that is being recommended to be provided by the generator to support its costs is contained in Appendix C. In addition to cost data, technical information on output, station use, fuel rate, capacity factor, availability, etc. is required. The assumed availability percentage is a key driver of the resulting tariff and the ERA must thoroughly review the estimated availability for the forecast period for reasonableness. Factors such as the age and condition of the plant are important as well as major maintenance outages anticipated.

Once the availability component of the tariff has been approved, it is up to the licensee to utilize prudent operating and maintenance practices to achieve that availability and, thereby recover all its fixed costs. If the licensee can exceed the estimated availability, it will recover an amount in excess of its fixed costs and earn a “Profit”, thereby providing the incentive. If it falls short of the estimated availability, it will incur a loss. The ERA must exercise its oversight authority, however, to insure that the generator is not deferring necessary periodic or major maintenance in order to keep the unit in service just to maximize its availability payments.

The other tariff component for generators is the Energy component. The ERA, therefore, must review the estimates for the variable costs. Generating units will be dispatched based on their variable costs and, therefore, in order to achieve economic dispatch, the energy component must be as accurate as possible. The information contained in Appendix C will assist the ERA in its review of the proposed costs. As time goes by, the ERA will be able to assess the accuracy of the generator’s forecast and be in a position to challenge the assumptions of subsequent forecasts.

Once the energy component of the tariff has been approved, it is up to the licensee to utilize prudent management practices in fuel procurement, operating, maintenance, and productivity management to achieve the estimated cost per kWh and, thereby recover all its variable costs. If the energy component of the tariff is set at the level of the actual variable costs, the generator should be indifferent as to whether it is dispatched or not.

In addition to providing standard availability and energy services to the market, generators are often required to supply ancillary services, which could include:

- Operating reserves
- Regulation and load frequency control
- Voltage control
- Black start capability

Provision of these services require the generator to be available at certain periods of time, as directed by the dispatcher, or to operate the unit in a manner to stabilize the system. The availability payment previously described is intended to compensate the generator for all its fixed costs. It is recommended that the availability factor submitted by the generator to the regulator for approval include its commitments to the Dispatch Licensee as far as being available at certain times. In that case, a separate ancillary service tariff to cover fixed costs is not required and the tariff process is simplified.

The other aspect of ancillary services has to do with operation of the power station in a manner that is not generally anticipated when developing the energy charge. The energy charge should fully compensate the generator for all energy provided to the system. However, if the generator is required by the dispatcher to operate the unit in a non-optimal manner, for example, to cycle up and down to follow the load or to keep one or more boilers “hot”, then the generator may incur additional operating costs (primarily fuel) not anticipated in its energy tariff. Generators that anticipate significant operating characteristics such as this as a result of their agreements with the dispatcher (specifically Power Station #4) should present a tariff proposal to the ERA to cover the additional cost. The generator’s approved energy tariff would cover the base energy cost and the ancillary service tariff would cover the incremental cost. Since the ancillary service tariff is unique to each generator, a formulistic approach is not practical. The main point is that the regulator should provide the vehicle for adequate cost recovery to the generator for all its prudent costs.

5.2 DETERMINING TOTAL REVENUE REQUIREMENTS OF GENERATORS

The revenue requirement will be calculated in accordance with the general methodology described in Chapter 4. To illustrate the methodology for determination of the various tariffs for a Generation Licensee, a set of sample data is presented to make the concepts more meaningful to the reader.

Assume that a Generation Licensee presents the following financial statements (with associated backup materials and cost allocations for the two separate licensed activities) as a forecast of the future 12-month period as shown in Exhibit 5.1.

Exhibit 5.1 Forecasted Financial Statements

BALANCE SHEET (millions Tg)		
Assets		
Current Assets		
Cash	1,000	
Inventories (Fuel & Spare Parts)	9,000	
Accounts Receivable	20,000	
Total Current Assets		30,000
Fixed Assets		
Cost	150,000	
Accumulated Depreciation	50,000	
Net Fixed Assets		100,000
TOTAL ASSETS		130,000
Liabilities and Equity		
Current Liabilities		
Accounts Payable	17,700	
Salaries Payable	100	
Taxes Payable	200	
Short-Term Debt (6%)	2,000	
Total Current Liabilities		20,000
Long-Term Debt (4%)		30,000
Equity		80,000
TOTAL LIABILITIES AND EQUITY		130,000

INCOME STATEMENT (millions Tg)		
Revenue (Current Tariffs)		41,000
Operating Expenses		
Fuel	20,000	
Salaries	4,050	
Employee Related benefits	1,000	
Depreciation	10,000	
Current Maintenance	3,000	
Other Operating Expenses	2,000	
TOTAL OPERATING EXPENSES		40,050
Non-Operating Expenses		
Short-Term Interest Expense	120	
Long-Term Interest Expense	1,200	
Taxes	130	
		1,450
NET INCOME		(500)

For purposes of this example, assume that the Licensee is proposing a return on equity of 8%, resulting in a Return on Investment of 6.9% as shown in Exhibit 5.2

Exhibit 5.2 Return on Investment

	RETURN ON INVESTMENT:			
Investment:				
	Fixed Assets		150,000	
	Accumulated Depreciation		(50,000)	
	Working Capital			
	Current Assets		30,000	
	Current Liabilities		(20,000)	
	Short-Term Debt		2,000	
	Net Investment			112,000

Cost of Capital:				
	Amount	**Percent**	**Cost (%)**	**Weighted Cost**
Long Term Debt	30,000	27%	4%	1.1%
Short-Term Debt	2,000	2%	6%	0.1%
Equity	80,000	71%	8%	5.7%
TOTALS	112,000	100%		6.9%

Return on Investment:	
Investment (Rate Base)	112,000
Rate of Return	6.9%
Return on Investment	7,720

5.3 ALLOCATING REVENUE REQUIREMENTS TO ELECTRICITY AND HEAT

Combined Heat and Power (CHP) stations are designed to produce both electricity and hot water for heating and other uses. Since these two “Products” are sold in different markets, a methodology must be adopted to allocate the total revenue requirement to each product. There is not a precise way to allocate the costs of a CHP power station to the production of heat and electricity, however, several methodologies have been developed and are being used in other countries to perform the fuel allocation. CHPs are built because they can produce electricity and heat using less fuel than it would take to produce the same quantities of electricity and heat in separate single function facilities. In general, allocation methods are concerned with the issue of how to allocate the fuel savings to the two "products" produced in the process (electricity and heat). Using boiler efficiencies and the overall efficiency of the power station operating in an electricity-only mode, the fuel savings can be estimated and allocated. The costs of the power station related to facilities (depreciation and return on investment) and other operating costs must also be allocated.

The power stations in Mongolia were constructed by Russians and operated by them for many years. The Russians devised a method to allocate fuel costs to electricity and heat production, but the method is not well understood by the current operating personnel. Compared to a variety of methods used in other countries, the method tends to allocate a higher percentage of fuel to electricity output. Documentation of the methodologies used in other countries has been provided to energy sector personnel and it has been recommended several times that they choose a more straightforward and conceptually sound method of fuel allocation. This should be accomplished within the next year and the resulting method consistently applied by each Licensee. Since there is an arbitrary subsidy between electricity and heat factored into the revenue requirement of each power station, however, the primary benefit of adopting a more rational method would be to properly quantify the subsidy.

As far as the costs other than fuel are concerned, the power sector has been utilizing an allocation of 70% to electric and 30% for heat based on a study performed several years ago. It is recommended that this study be revised and that more detailed allocations be developed.

5.3.1 Cost Allocation Requirements

To illustrate the principles of cost allocation, an example has been developed to give the reader an appreciation of the details. The primary cost to allocate is fuel and it is assumed that the power station has applied a methodology approved by the ERA, most likely to be based on the proportional amount of heat energy generated for each process. Other operating costs must also be allocated based on rational criteria for the primary components as follows:

- Labor costs should be allocated based on the primary areas where people work. For example, boiler and fuel handling related costs should be allocated based on heat output; turbine generator costs should be assigned to electric, and so forth.
- Employee related costs such as benefits and taxes, should be allocated based on salary costs
- Current maintenance costs for the year should be based on an analysis of the major projects.
- Miscellaneous costs such as administration and training should be prorated based on all other operating costs

Assume that the Licensee has performed a comprehensive analysis and presents the information shown in Exhibit 5.3 to the ERA as part of its tariff application. These allocation factors are necessary to be able to allocate the operating costs shown in Exhibit 5.1 to the two lines of business.

Exhibit 5.3 Operating Cost Allocation

Operating Cost Allocation

Classification	Method	Assumed Percent Electric	Assumed Percent Heat
Fuel	A	55%	45%
Salaries	B	60%	40%
Employee Related benefits	S	60%	40%
Current Maintenance	T	75%	25%
Other Operating Expenses	P	70%	30%

Methods

A	Allocate based on proportional heat energy generated
B	Analysis of where people work (Boiler, Fuel Hanling Turbine, etc.)
S	Prorate based on Salaries
T	Based on an alalysis of projects
P	Miscellaneous costs prorated based on all other costs (above)

Allocation factors must also be developed for fixed assets and related items. Exhibit 5.4 shows assumed allocation factors for the major categories of equipment developed and submitted by the licensee as part of the tariff application.

Exhibit 5.4 Fixed Asset Allocation Factors

Fixed Asset Allocation

Classification	Method	Assumed Percent Electric	Assumed Percent Heat
Fuel Handling	A	55%	45%
Boiler and Associated	A	55%	45%
Turbinegenerator	E	100%	0%
Plant Electrical Equipment	E	100%	0%
Heat Specific equipment	H	0%	100%
Buildings	M	70%	30%
Misc. (office, etc)	M	70%	30%

Methods

A	Allocate based on proportional heat energy generated
E	Assume 100% Electric Related
H	Assign 100% to Heat
M	Miscellaneous common facilities prorated based on all other facilities

The Licensee also submits details of its fixed asset related costs as shown in Exhibit 5.5.

Exhibit 5.5 Fixed Asset Related Costs

Fixed Asset Related Costs (Millions Tg)			
Categories	**Investment**	**Accumulated Depreciation**	**Annual Depreciation**
Fuel Handling	20,000	7,000	1,200
Boiler and Associated	55,000	20,000	3,800
Turbinegenerator	30,000	10,000	2,000
Plant Electrical Equipment	10,000	3,000	700
Heat Specific equipment	8,000	2,000	500
Buildings	15,000	5,000	1,000
Misc. (office, etc)	12,000	3,000	800
TOTALS	**150,000**	**50,000**	**10,000**

5.3.2 Revenue Requirements by Line of Business

The allocation factors developed must then be applied to the various cost elements in order to arrive at revenue requirements for the electricity and heat license activities (also referred to as lines of business, or functions).

The fixed asset allocation factors shown in Exhibit 5.4 must be applied to the costs in Exhibit 5.5, to determine the Investment (or Rate Base) by line of business. Working Capital represents a short-term investment. For this example, it is assumed that since fuel inventory is a significant ingredient, the working capital is allocated based on the same percentage as fuel. The previously determined rate of return (Exhibit 5.2) is then applied to the investment to determine the Return on Investment as shown in Exhibit 5.6.

Exhibit 5.6 Return on Investment by Licensed Activity

Return on Investment by Function (millions Tg)	**Total**	**Electric**	**Heat**
Investment			
Fixed Assets	150,000	100,150	49,850
Accumulated Depreciation	(50,000)	(33,450)	(16,550)
Working Capital	12,000	6,600	5,400
TOTAL INVESTMENT	112,000	73,300	38,700
Rate of Return	6.9%	6.9%	6.9%
Return on Investment	7,720	5,052	2,668

The information is now available to calculate the revenue requirements for electricity and heat. Exhibit 5.7 displays the results of the application of the allocation factors discussed previously to the detailed cost elements. Taxes were assumed to be allocated 100% to electricity since it is the only "profitable" line of business.

Exhibit 5.7 Revenue Requirements by Licensed Activity

	REVENUE REQUIREMENT (millions Tg)	Total	Electric	Heat
I.	**Operation and Maintenance**			
	Fuel	20,000	11,000	9,000
	Salaries	4,050	2,430	1,620
	Employee Related benefits	1,000	600	400
	Current Maintenance	3,000	2,250	750
	Other Operating Expenses	2,000	1,400	600
	TOTAL	30,050	17,680	12,370
II.	**Depreciation**	10,000	6,710	3,290
III.	**Taxes**	130	130	0
!V.	**Return on Investment**	7,720	5,052	2,668
	TOTAL REVENUE REQUIREMENT	**47,900**	**29,572**	**18,328**

The next step is to utilize these revenue requirements to develop tariffs.

5.4 TARIFFS FOR ELECTRICITY

A common practice in most countries is to have the electricity line of business subsidize the heat line of business. In Mongolia, this is currently accomplished at the power station level by transferring an average of over 40% (depending on the power station) of the heat revenue requirement to the electric revenue requirement prior to designing the tariffs. As discussed in Chapter 12, Subsidies, customers of the Central Heat Systems in Ulaanbaatar, Darkhan, and Erdenet living in apartments experience a significantly lower cost to heat their homes than those households living in ger districts. For this reason, it is recommended that the subsidies be gradually reduced over a period of several years to bring heat tariffs for apartments closer to the cost of service, thereby relieving some of the pressure on electricity tariffs. The following tariff calculations assume a 40% cost subsidy to heat for example purposes.

In addition to the revenue requirement information previously developed, operating and technical information is needed in order to calculate tariffs. A summary of that information is shown in Exhibit 5.8.

Exhibit 5.8 Operating Information

Power Station Operating Information Forecast for Year	
Gross Plant Generation (MWH)	1,400,000
Station Use at 17% (MWH)	238,000
Net Station Output (MWH)	1,162,000
Installed Capacity (MW)	500
Average Availlable Capacity (MW):	
Winter	400
Summer	300
Average	350
Heat Output (Th of Gcal)	2,500

5.4.1 Energy Tariff

The energy tariff for electricity output is intended to compensate the power station for its variable costs. Fuel is obviously a variable cost. Most other costs of a power station are fixed. Depreciation and Return on Investment are related to the fixed assets and do not vary in the short run with output. Most maintenance costs are also fixed based on the requirements to maintain the equipment. Employee related costs (Salaries and benefits) do not vary, for the most part, based on day-to-day operations. To determine the Energy Tariff, it is assumed that fuel costs are variable as well as a portion (assumed to be equal to 10% of fuel expense) of other Operating and Maintenance costs. The 10% is an assumed value intended to represent the fact that some other operating costs are variable with output including:

- Fuel Handling
- A portion of Salaries
- Some Current Maintenance that pertains to the operating hours of equipment

Exhibit 5.9 displays the calculation of the Energy Tariff determined based on a revenue requirement equal to electric fuel cost plus 10% divided by net station output, resulting in a tariff of 10.41 Tg/kWh.

5.4.2 Availability Tariff

The Availability Tariff is intended to compensate the power station for its fixed costs as a result of it being available for dispatch by the Dispatcher. The Market Rules should specify the specifics of the application of this tariff, but basically, it is a tariff (Tg/KW/day) that is paid to the power station each day based on the capacity (in KW) that it declares as available to be dispatched. The tariff parameters must be carefully determined by the Licensee based on its commitments (which vary by time of year, anticipated heat load, etc.) to the Dispatch Licensee. The ERA must analyze the tariff submission for reasonableness in light of prior history and the forecasted demands and energy output requirements for the coming year. Each day the

Licensee would declare an amount of capacity (KW) available for dispatch and as a result receive an availability payment from the Wholesale Market equal to the number of KW declared times the daily tariff. In order to prevent generators from declaring an amount of capacity as available, when it truly is not, the Market Rules should specify penalties for "Gaming the System".

The subsidy for heat is assumed to be included in the Availability Tariff. The cost to be recovered in the Availability Tariff is, therefore equal to

The total electric revenue requirement of the power station,

LESS the energy related revenue requirement (fuel cost + 10%)

PLUS the heat subsidy

The resulting cost is divided by the weighted average availability for the year and then divided by 365 to arrive at the daily Availability Tariff of 194 Tg/KW as shown in Exhibit 5.9

Exhibit 5.9 Tariff Calculations

Tariff Calculations	
Electric	
Energy Tariff:	
Fuel Cost (mil Tg)	11,000
Plus 10%	1,100
Revenue Requirement	12,100
Net Station Output (MWH)	1,162,000
Tariff (Tg/kWh)	**10.41**
Availability Tariff	
Total Revenue Requirement	29,572
Less Energy Related	12,100
Subsidy to Heat	7,331
Capacity Related Cost	24,803
Average Availability (MW)	350
Capacity Cost per KW (Tg/KW)	70,867
Daily Availability Tariff (Tg/KW)	**194**
Heat	
Revenue Requirement (mil Tg)	18,328
Less Subsidy (40%)	7,331
Net Revenue Requirement	10,997
Heat Output (Th of Gcal)	2,500
Tariff (Tg/Gcal)	**4,399**

5.4.3 Ancillary Services Tariff

As discussed in Section 5.1.1, an Ancillary Services Tariff may also be required to properly compensate generators. At the present time, UB Power Station #4 is the primary generator that is required to provide the service of load following during the day. Discussions have been held with operating and engineering personnel at UB4 and the situation is that the power station is required to keep at least one boiler hot requiring the burning of mazut and, in some cases, coal in order to be able to produce incremental amounts of electricity needed by the dispatcher as the load fluctuates throughout the day. Of course, since the fuel burned in a standby mode does not result in electricity production, the power station would not have the opportunity to recover the fuel cost. In addition, metal fatigue is a significant issue with boilers that are cycled up and down in order to follow the load. The power station must factor excess maintenance into the cost of load following, in addition to the coal and mazut costs.

UB4 is in the process of quantifying the cost of providing this ancillary service and will present the results to the ERA and the Dispatch Licensee. This will result in the cost being quantified and a tariff can then be developed. The quantification will also provide useful information to the Dispatch Licensee so it can make the decision (in real time) as to whether it is more economic to utilize imported power for load following or to use UB4, based on relative economics.

5.4.4 Fuel Adjustment Mechanism

The Generation Licensees must be encouraged to effectively utilize their fuel resources to achieve the lowest fuel rates possible, given the condition of the units and prudent operation and maintenance practices. Since generators have very little control over the unit price of fuel, however, a mechanism has been developed to adjust the energy component of the tariff at the time unit fuel prices are increased (both coal and mazut). Likewise, generators have very little control over coal transportation costs and should adjust the energy component of the tariff at the time rail tariffs increase.

Power stations should not speculate on fuel price changes. Their base tariff should reflect current fuel prices at the time the base tariff is set. A Fuel Adjustment mechanism would be utilized when fuel prices or transportation costs are changed and result in an adder to the energy tariff to capture ONLY those unit price changes. No other changes (e.g. salaries) should be allowed.

An example of the proposed mechanism was developed to illustrate how it would operate. The results are shown in Exhibit 5.10. The basic elements of the mechanism include:

- The starting point of a complete documentation of the fuel cost included in the base tariff for electricity and heat output (the first column of data in Exhibit 5.10)
- Changes will be allowed only for the following (see second column of Exhibit 5.10):
  - Price per ton of coal from the particular source (mine)
  - Price per ton for rail transportation
  - Price per ton of Mazut
- A recalculation will be made to determine the revised fuel costs per unit of output (kWh and Gcal) to be used in the future, as shown in the third column.
- Once the data has been reviewed by the ERA, the Energy Tariffs contained in the Power Purchase Agreements will be adjusted

- Of course, the increased costs must then be passed on to the Wholesale Market, and ultimately to Retail Customers.

Exhibit 5.10 Fuel Cost Adjustment Mechanism Example

FUEL COST DETERMINATION		Included in Original Tariff	Changes	Base Quantities at New Unit Prices
Coal - Mine Cost		1,425,000		1,477,500
Baganuur		930,000		960,000
	Tons	100,000		100,000
	Unit Cost	9,300	9,600	9,600
Sharyn-Gol		495,000		517,500
	Tons	45,000		45,000
	Unit Cost	11,000	11,500	11,500
Shivee Ovoo		0		0
	Tons	0		0
	Unit Cost	6,000	6,400	6,400
Transportation Cost		214,368		217,500
	Tons	145,000		145,000
	Unit Cost	1,478	1,500	1,500
Mazut Cost		140,000		147,500
	Tons	500		500
	Unit cost	280,000	295,000	295,000
Other Miscelaneous Costs		75,000		75,000
TOTAL FUEL COSTS		1,854,368		1,917,500
Allocation of Fuel Costs				
Electricity		55%		55%
Heat		45%		45%
Fuel Cost by License Activity				
Electricity		1,019,902		1,054,625
Heat		834,466		862,875
Output Measures				
Electricity (000 kWh)		90,000		90,000
Heat (Gcal)		200		200
Price per Unit				
Electricity (Tg/kWh)		11.33		11.72
Heat (Tg/Gcal)		4,172		4,314
Price Change				
Electricity (Tg/kWh)			0.39	3.4%
Heat (Tg/Gcal)			142.05	3.4%

5.5 TARIFFS FOR HEAT OUTPUT

As discussed in Section 5.4, the subsidy from electricity to heat is applied at the power station level and presently amounts to over 40% of the heat revenue requirement. The heat revenue requirement used to develop tariffs is, therefore, far below the cost of service. In fact, on average for the power stations in the CES, heat tariffs of power stations barely recover the cost of fuel, let alone any of the other operating expenses or facility related costs. This subsidy should be gradually reduced over a period of years. As in most countries, however, a subsidy from electricity to heat will continue. The tariff calculation shown in Exhibit 5.9 assumes a 40% subsidy. The remaining Revenue Requirement is recovered based on the heat output of the power station and the resulting tariff is 4,399 Tg per Gcal. Of course, the heat tariff would be adjusted during the year based on the Fuel Adjustment Mechanism, in the event of fuel cost changes that were not anticipated in the base tariff.

5.6 INCENTIVE MECHANISMS

The market and tariff mechanisms discussed in this chapter provide significant opportunities to implement incentive regulation concepts.

A generator receives the availability payment for the day if it declares itself as being available. The amount is based on the fixed costs of the power station and the assumed availability factor. Least cost overall is achieved if the unit is available as much as possible, given prudent maintenance practices. Once the availability component of the tariff has been approved, it is up to the licensee to utilize prudent operating and maintenance practices to achieve that availability and, thereby recover all its fixed costs. If the licensee can exceed the estimated availability, it will recover an amount in excess of its fixed costs and earn a “Profit”, thereby providing the incentive. If it falls short of the estimated availability, it will incur a loss. The ERA must exercise its oversight authority, however, to insure that the generator is not deferring necessary periodic or major maintenance in order to keep the unit in service just to maximize its availability payments. Properly designed Market Rules will also provide effective controls.

The other tariff component for generators is the Energy component. The ERA, therefore, must carefully review the estimates for the variable costs. Generating units will be dispatched based on their variable costs and, therefore, in order to achieve economic dispatch, the energy component must be as accurate as possible. The energy component approved by the ERA can be considered as a price cap. An incentive exists, therefore, for generators to attempt to have their approved tariff (price cap) be as high as possible. This presents a challenge to the ERA to closely examine the drivers of the energy component (purchase price of fuel, transportation cost, heat content of the fuel, and the fuel rate of the power station) to insure against the potential upward bias on the part of the Licensee. Other factors such as the forecasted fuel rate and station use are also primary drivers of energy costs. Once the energy component of the tariff has been approved, it is up to the Licensee to utilize prudent management practices in fuel procurement, operating, maintenance, and productivity management to achieve the estimated cost per kWh and, thereby recover all its variable costs. If the Licensee can implement meaningful cost reduction programs, it will recover an amount in excess of its estimated variable costs and earn a “Profit”, thereby providing the incentive. If it falls short of the estimated cost per kWh, it will incur a loss. As long as the energy component of the tariff is set at the level of the actual reasonable variable costs, the generator should be indifferent as to whether it is dispatched or not.

The ERA, therefore, must exercise its oversight authority to insure that the various tariffs are properly determined in order for the market structure to work properly.

5.7 TRANSITION ISSUES

As discussed in Section 5.1.2, in order for the Single Buyer Market mechanisms to work properly, Market Rules must be established and adhered to by the market participants (Licensees). Market Rules define in great detail the relationships between the parties (generators, the dispatcher, and the Single Buyer) and are needed in order to have a transparent, efficient, and economic market. Technical assistance is required to guide the Dispatcher, Single Buyer, and Generation Licensees as they develop the market rules. The ERA will also require technical assistance to define their role in monitoring market operations.

Several discussions have been held with the Dispatcher, Generators, and the ERA as far as economic dispatch is concerned. The two-part generator tariff can be implemented in the near term and the Dispatcher is prepared to implement economic dispatch based on the marginal cost (Energy Tariff) of each power station, given the various constraints of heat load, etc.

There is a concern, however, about the most appropriate manner in which to first determine the Availability Tariff for each generator and second to utilize the concept of declared availability in order to compensate generators for their fixed costs. Without a detailed set of market rules, the availability tariff is difficult to design and utilize. An interim mechanism will, therefore, be employed until market rules can be developed. The Availability Tariff will be calculated in a more elementary manner than shown in Exhibit 5.9. The Capacity Related Cost for the year (24,803 million Tg per Exhibit 5.9) will be divided by 12 and that amount will be paid monthly to the generator by the Wholesale Market. This will preclude the need to determine the projected availability of each power station and to verify on a daily basis the amount of capacity a power station actually has available to the market.

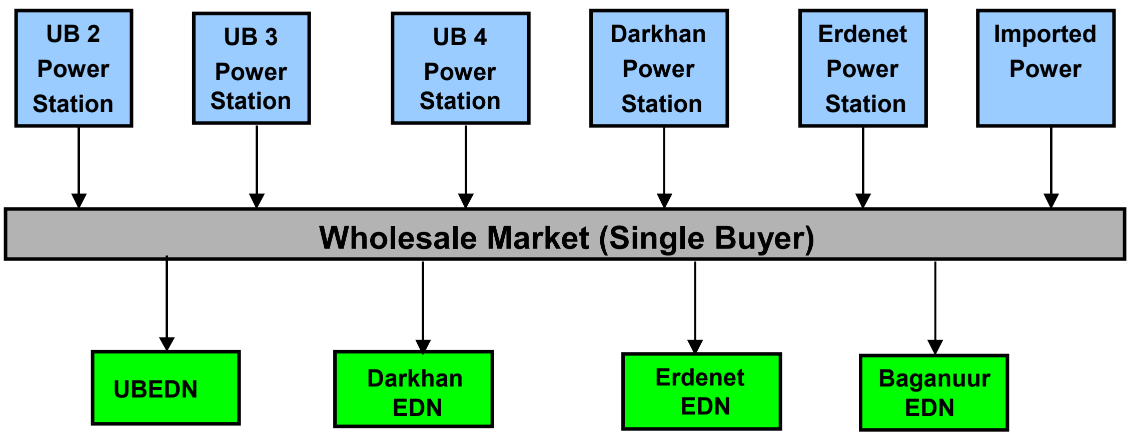
This interim mechanism does not, of course, offer an incentive to the licensee to have the power station available for dispatch as much as possible, as discussed in Section 5.6. The Single Buyer, in conjunction with ERA, will have to determine minimum availability standards for each power station (by time of year) in order for the power station to be eligible for the full availability payment. The objective here is not to exercise command and control over the Licensee or to generate penalty revenue, but rather to substitute for the operation of the market mechanisms.

6. DETERMINING WHOLESALE MARKET PRICES

6.1 OVERVIEW OF THE WHOLESALE MARKET

The Wholesale Market functions as an intermediary market in which power suppliers to the Central Electricity System (CES) sell their output to a Single Buyer (a function performed by the Transmission Company). Power is then resold to the Distribution/Supply Companies. The market structure is depicted in Exhibit 6.1.

Exhibit 6.1 Wholesale Market Structure in CES



6.2 PURCHASE TRANSACTIONS OF THE WHOLESALE MARKET

The wholesale market incurs costs to acquire energy from generators and import transactions as well as the cost of market operation.

6.2.1 Power Station Transactions

Each power station will have a Power Purchase Agreement specifying an Availability Price (Tg/KW) and an Energy Price (Tg/kWh) at which they will sell their output to the Wholesale Market. The prices will be approved by the ERA. Energy prices for each Generation Licensee will include a base energy price plus any fuel cost adjustment charge. In addition, certain power stations may provide ancillary services to the system and have a tariff for those services. See Chapter 5 for the specifics of the price determination for generators.

6.2.2 Power Imports and Exports

The agreement with Russia specifies the pricing of imported power from Russia and the pricing of power flows from Mongolia to Russia. The power exchange arrangement between Russia and Mongolia can basically be characterized as a net import arrangement for Mongolia. A very significant benefit of the arrangement to Mongolia is the ability to be connected to the Russian power grid, providing stability and voltage and frequency control to the CES. Imports of power amount to approximately 5% of the total power requirements of the CES.

The agreement calls for a fixed capacity payment of 180,000 USD per month and an energy charge of 1.4 US cents per kWh for power sales to Mongolia. The power flows from Mongolia to Russia are basically treated as inadvertent flows and priced at a significantly lower price, indicating that Russia does not have a significant need for the power. During the higher load periods of the first and fourth quarters of the year, the power flows from Mongolia to Russia are priced at 50% of the energy charge (0.7 US cents) and, during the lower load periods of the second and third quarters, they are priced at 26% of the energy charge (0.35 US cents). These export prices are below the cost of fuel at the most efficient power station in Mongolia (UB # 4). There is no capacity payment for power flows from Mongolia to Russia. The Dispatch Licensee, therefore, attempts to minimize power flows to Russia, with the resulting flows being for system stability or inadvertent. For these reasons, the box labeled "Imported Power" is actually the net of Russian imports and exports. The Wholesale Market pricing for this power is in accordance with the agreement with Russia.

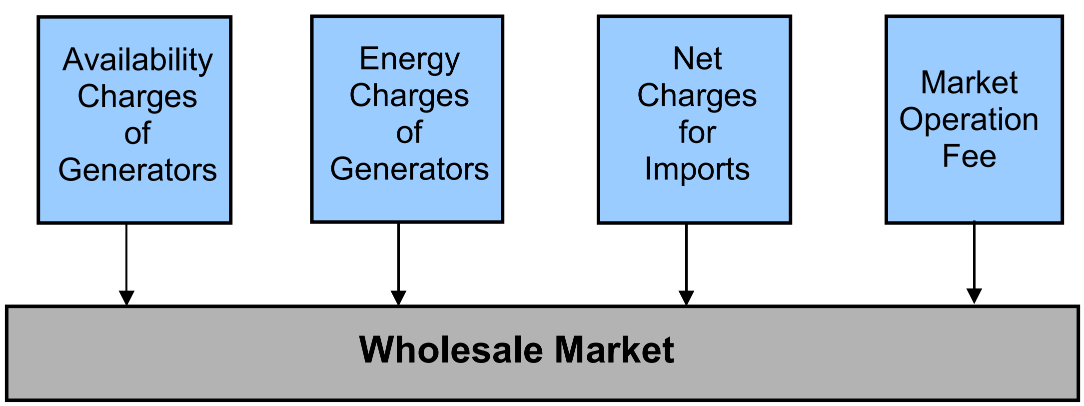
6.2.3 Market Operation Costs

The Transmission Company incurs costs in order to operate the market and, at the present time, manage the Cash Settlement Procedure. It must recover these costs through a Market Operation Fee that it will charge to the Wholesale Market Account. See Chapter 7 for a discussion of the development of that fee.

6.2.4 Costs Incurred by the Wholesale Market

The costs incurred by the wholesale market can therefore be depicted as shown in Exhibit 6.2

Exhibit 6.2 Wholesale Market Costs



6.3 SALES TO WHOLESALE CUSTOMERS

The Distribution/Retail Supply Licensees purchase their power requirements from the Wholesale Market. The objective is to develop a wholesale pricing system (often called a Bulk Supply Tariff) that will allow the Wholesale Market Operator (the Single Buyer) to recover all payments made to generators, payments for imported power, and the costs required to operate the market. The ideal situation would be to have a pricing mechanism to charge purchasers the actual capacity payments per day based on the demands they place on the system and charge them for energy based on the actual cost experienced by the market for each hour. That would send the appropriate price signals to the market and enable purchasers to have some control over their cost and ultimately charge customers (especially large consumers) based on time of use. That is not possible due to metering constraints and the complexity of such a system.

Alternatively, the Wholesale Market Operator (Single Buyer) could develop a rather simple system of determining an overall cost of power by accumulating all costs incurred by the market for a month, dividing that by the kWh sales to each customer for the month, and charging a uniform price per kWh to each purchaser (the market clearing price). In that manner, the wholesale market account would not be in an over or under recovery position at the end of the month. Of course, such a methodology would result in the unit cost of power purchases varying each month. This is normal due to the varying mix of generation and volume fluctuations each month.

The ERA currently controls the wholesale market purchase price to each distribution entity in order to have a uniform retail tariff in the CES. The starting point is actually the retail tariff. When the transmission, distribution, and supply tariffs are subtracted from the target retail tariff, the unit power purchase price is determined (considering the specific technical and commercial losses of each Distribution Licensee). . This results in the Distribution Licensees with high energy losses and distribution tariffs to pay a lower wholesale market price than the lower cost Licensees. Of course, this also results in subsidies from the low cost licensees to the higher cost licensees. The Ulaanbaatar and Darkhan Networks have high technical and commercial losses and high distribution fees and, therefore, receive a subsidy from other customers in CES. This pricing mechanism must be discontinued. In fact, the ERA (as well as the Government of Mongolia) must allow the unbundled market structure to operate properly. That means that the retail prices should be determined for each Distribution / Supply Licensee based on the cost of each of the component licensee tariffs including:

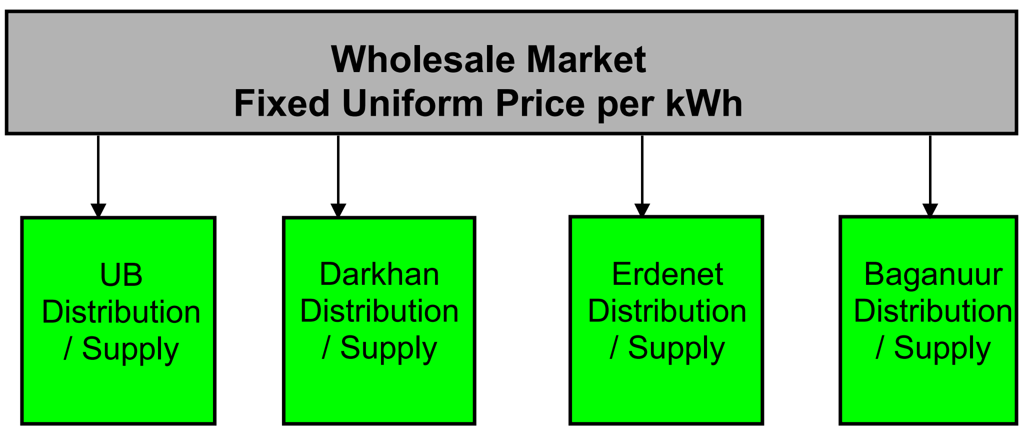
- Wholesale Market Price
- Transmission Network Tariff
- Distribution Tariff
- Retail Supply Tariff
- Dispatch Fee

The resulting retail tariff is, therefore, the sum of the individual components. This is a bottom-up approach as opposed to the top-down methodology currently being used. As discussed in Section 6.5, immediate application of this pricing mechanism would result in significant tariff increases for Ulaanbaatar and Darkhan Distribution Networks and significant decreases for Erdenet Distribution Network. To prevent these shocks to the market, a two-year phase in mechanism will be utilized. See Section 6.5 for further details.

The ERA realizes the importance of having the wholesale market clear each month, however, they also desire the retail tariffs to remain stable for a period of time of approximately six months. ERA feels that the customers are not ready for retail prices that change each month based on the fluctuations in wholesale power costs. Also, the Retail Supply Licensees would incur costs to have their billing systems accommodate monthly changes in each of the retail tariffs. For these reasons, a mechanism must be developed in order to charge a uniform fixed wholesale power cost to each Distribution / Supply Licensee based on an estimated market clearing price (determined by the Single Buyer and approved by the ERA) for the upcoming six-month period. This will result in a market imbalance (over or under recovered position) that must be adjusted in the following six-month period. It is very important for the reader to understand that the Wholesale Market Account (purchases from generators and sales to the distribution companies) is MANAGED by the Transmission Company. It is NOT part of their revenues and expenses and, therefore, any over or under recoveries (market imbalances) are not part of the Transmission Company income or loss.

Wholesale Market Sales transactions can be depicted as shown in Exhibit 6.3.

Exhibit 6.3 Wholesale Market Sales Transactions



6.4 WHOLESALE MARKET PRICING EXAMPLE

In order to illustrate the proposed methodology, an example has been developed. Assume that all Licensees submit tariff applications to ERA in the fall of the year for review and approval. ERA will review the tariff applications, which include estimated volumes of energy. A review of the Distribution/Supply Licensee tariff applications will be made to determine the estimated sales to customers and resulting requirements for wholesale purchases. An energy balance will be performed to determine generation and import requirements. Availability and base energy tariffs for each generator will be developed for the coming year. Of course, in the event that the price of fuel changes during the year, there may also be a Fuel Adjustment charge in addition to the base energy charge.

Assume that the forecasted energy balance for the first six-month period of the upcoming year (Q 1&2), the second six-month period (Q3&4), and the total year is as shown in Exhibit 6.4.

Exhibit 6.4 Forecasted Energy Balance

	Q 1&2	Q 3&4	Total
Generation			
UB #2	49,000	45,000	94,000
UB #3	195,000	220,000	415,000
UB #4	750,000	850,000	1,600,000
Darkhan	95,000	110,000	205,000
Erdenet	55,000	40,000	95,000
Net Import	50,000	70,000	120,000
Total Supply	1,194,000	1,335,000	2,529,000
Transmission Losses (3.5%)	41,790	46,725	88,515
Available for Distribution	1,152,210	1,288,275	2,440,485
Sales to Distribution Licensees			
UBEDN	450,000	490,000	940,000
Darkhan EDN	120,000	130,000	250,000
Erdenet EDN	490,000	560,000	1,050,000
Baganuur EDN	92,210	108,275	200,485
Total Sales	**1,152,210**	**1,288,275**	**2,440,485**

The next step is to estimate the wholesale market price by applying the newly developed tariffs for each licensee to the forecasted volumes of energy as shown in Exhibit 6.5.

Exhibit 6.5 Wholesale Price Estimates

	Q 1&2	Q 3&4	Total
Costs (millions of Tg)			
UB #2	1,617	1,485	3,102
UB #3	8,385	9,460	17,845
UB #4	17,250	19,550	36,800
Darkhan	3,420	3,960	7,380
Erdenet	2,310	1,680	3,990
Net Import	1,500	2,100	3,600
Market Operation Fee	180	180	360
Total Costs	34,662	38,415	73,077
Wholesale Sales (MWH)	1,152,210	1,288,275	2,440,485
Wholesale Price (Tg/kWh)	**30.08**	**29.82**	

The estimated amounts shown for each power station include availability payments and energy payments, including any anticipated fuel price adjustments. The Wholesale price of 30.08 Tg/kWh would be charged to each wholesale customer for all energy received in the first half of the year.

Of course, at the end of the first 6 months, the market will either be in an over recovered (sales revenue in excess of costs) or under recovered (costs in excess of revenue) situation. Reconciliation will be required to correct the imbalance. The over or under recovery amount for the first six months will be determined and this amount will be recovered over the second six months as a specific charge per estimated kWh to be sold during the second six month period. As shown in Exhibit 6.6, the Wholesale Market Price for the third and fourth quarters would include a charge of 29.82 Tg/kWh based on estimated costs in that period plus an adjustment amount of 0.31 Tg/kWh, for a total wholesale market price of 30.13 Tg/kWh.

Exhibit 6.6 Market Reconciliation and Subsequent Pricing

Costs Incurred (mil Tg)	35,000
Billings to Customers (mil Tg)	34,600
Under Recovery (mil Tg)	400
Estimated Sales for Q3&4 (MWH)	1,288,275
Market Adjustment Charge (Tg/kWh)	0.31
Market Price for Q3&4 (Tg/kWh):	
Estimated Q3&4 Price	29.82
Adjustment Charge	0.31
Wholesale Market Tariff	**30.13**

6.5 WHOLESALE MARKET TRANSITION ISSUES

The ERA currently controls the wholesale market purchase price to each distribution entity in order to have a uniform retail tariff in the CES. The starting point is actually the retail tariff. When the transmission, distribution, and supply tariffs are subtracted from the target retail tariff, the unit power purchase price is determined (considering the specific technical and commercial losses of each Distribution Licensee). This results in the Distribution Licensees with high levels of energy losses and distribution tariffs to pay a lower wholesale market price than the lower cost Licensees. Of course, this also results in subsidies from the low cost licensees to the higher cost licensees. The Ulaanbaatar and Darkhan Networks have high technical and commercial losses and high distribution fees and, therefore, receive a subsidy from other customers in CES.

Immediate application of the pricing mechanisms discussed in Sections 6.3 and 6.4 would result in significant tariff increases for Ulaanbaatar and Darkhan Distribution Networks and significant decreases for Erdenet Distribution Network. To prevent these shocks to the market, a two-year phase in mechanism will be utilized. The phase-in can best be illustrated using the following example.

Exhibit 6.7 displays the current situation with each Distribution Licensee paying different wholesale prices (for energy plus transmission fee). When losses and the distribution and supply fees are applied, the resulting average retail tariffs (considering time-of-use discounts, etc.) for each Licensee are shown in the far right column.

Exhibit 6.7 Current Situation of Wholesale Pricing

Licensee	Wholesale Price (Tg/kWh)	Losses (%)	Gross Energy Price (Tg/kWh)	Dist & Supply Fee (Tg/kWh)	Average Retail Tariff (Tg/kWh)
UB	26.86	29.40%	38.05	8.02	46.07
Darkhan	27.79	22.52%	35.87	6.95	42.82
Erdenet	39.84	4.00%	41.50	2.41	43.91
Baganuur	31.81	13.40%	36.73	9.85	46.58
Average	32.48				

Given that the average wholesale price is 32.48 Tg/kWh, UB and Darkhan pay approximately 15% less, Erdenet pays 23% more, and Baganuur pays approximately the average. The ERA desires to minimize the shock of tariff adjustments and, therefore, a phase-in mechanism that will gradually bring the 4 Licensees to the average wholesale price over a period of two years has been developed. The mechanism moves UB, Darkhan, and Erdenet closer to the average wholesale price by applying a transparent subsidy as shown in the third column of Exhibit 6.8.

Exhibit 6.8 Example of First Year Phase-In Mechanism

Licensee	Base Wholesale Price (Tg/kWh)	Subsidy (Tg/kWh)	Final Wholesale Price (Tg/kWh)	Losses (%)	Gross Energy Price (Tg/kWh)	Dist & Supply Fee (Tg/kWh)	Average Retail Tariff (Tg/kWh)	Increase (%)
UB	32.48	(2.80)	29.68	29.40%	42.04	8.02	50.06	8.7%
Darkhan	32.48	(2.50)	29.98	22.52%	38.69	6.95	45.64	6.6%
Erdenet	32.48	3.66	36.14	4.00%	37.65	2.41	40.06	-8.8%
Baganuur	32.48		32.48	13.40%	37.51	9.85	47.36	1.7%
Average	32.48		32.48					

The resulting effect on retail tariffs would be to increase UB and Darkhan retail tariffs by 8.7% and 6.6%, respectively and to reduce Erdenet tariffs by 8.8% (excluding, of course, any other changes in cost levels, etc.). In the second year, the wholesale market prices would be set at the average for each licensee (the ultimate objective) resulting in additional increases for UB (7.9%) and Darkhan (7.1%) and a further decrease for Erdenet of 9.5%, as shown in Exhibit 6.9. This transition mechanism accomplishes the objective of having a uniform wholesale tariff in a relatively short period of time, while minimizing the shock on customers.

Exhibit 6.9 Example of Second Year Phase-In Mechanism

Licensee	Wholesale Price (Tg/kWh)	Losses (%)	Gross Energy Price (Tg/kWh)	Dist & Supply Fee (Tg/kWh)	Average Retail Tariff (Tg/kWh)	Increase over Year 1 (%)
UB	32.48	29.40%	46.01	8.02	54.03	7.9%
Darkhan	32.48	22.52%	41.92	6.95	48.87	7.1%
Erdenet	32.48	4.00%	33.83	2.41	36.24	-9.5%
Baganuur	32.48	13.40%	37.51	9.85	47.36	0.0%
Average	32.48					

7. TARIFF METHODOLOGY FOR THE TRANSMISSION LICENSEE

7.1 OVERVIEW OF THE TRANSMISSION FUNCTION

At the present time, the Transmission Company provides two distinct services to the Central Electricity System including:

- Ownership, operation, and maintenance of the transmission network
- Market Operations including the Single Buyer (wholesale market operation) function and the Cash Settlement Procedure function.

Ideally, each of these functions should be separately licensed since they are distinct services. Also, to minimize the opportunity for abuse of power, separation of duties would be a wise move. The Energy Law does not provide for licenses for the Single Buyer or Market Banker functions, therefore, the Transmission Company has been assigned to carry out those functions. The ERA must require the Transmission Company to separately account for these functions, in order that tariffs can be appropriately established. It is very important for the reader to understand that the Wholesale Market Account (purchases from generators and sales to the distribution companies) is MANAGED by the Transmission Company. It is NOT part of their revenues and expenses and, therefore, any over or under recoveries (market imbalances) are not part of the Transmission Company income or loss.

Recommended tariffs for each of the services are presented in the following sections.

7.2 NETWORK SERVICES TARIFF

The Transmission Licensee owns, operates, and maintains the physical transmission network. As in most markets, the transmission function is a regulated monopoly. A Network Services tariff is needed to recover the costs related to the transmission network. The first step is to determine the Revenue Requirement to be recovered by the Transmission Company for the network and the second is to determine how that revenue requirement is to be recovered.

The revenue requirement should include the following costs related to the transmission network:

- Operating and Maintenance Expenses
  - Salaries
  - Employee benefit and other employment related costs
  - Current maintenance
  - Other Operating Costs (Administration, etc)
- Depreciation
- Taxes
- Return on Investment

The Central Electricity System is a small one; therefore, the tariff should not be complex. In some systems, since generators are connected to the transmission system and benefit from it, they are assessed for the use they make of it. In the case of Mongolia, however, it is recommended that no transmission connection or usage charges be applied to generators. All Transmission Network charges will only be assessed to Load Customers, in this case the Distribution Licensees.

In some power systems, users of the transmission system are assessed for the use of that system based on a variety of factors, including demands placed on the system, the distance from generation sources, congestion factors, etc. In the Central Electricity System, there are no congestion problems or constraints on the transmission system and, therefore, it is recommended that the Network Services Tariff be assessed on the basis of the "Postage Stamp" method. Under this method, there is no price differentiation for location or transmission constraints. To keep the tariff as simple as possible, the total estimated revenue requirement for the following 12-month period would be divided by the estimated energy deliveries (in kWh) from the transmission system to the Wholesale Market customers (the Distribution Licensees). In the future, as new generation is added, the ERA may decide to utilize more sophisticated pricing mechanisms, if the situation at that time warrants.

Since the tariff is based on estimated costs and estimated volumes of energy flowing over the system, there will be either an over-collection or under-collection of actual costs during the period of time (say one year) that the tariff is in effect. At the end of the 12-month period, the Transmission Company should present a reconciliation of the amount recovered and the actual costs incurred to the ERA. After a review for prudence, the ERA should allow the Transmission Company to include the over or under recovered amount (assuming it is significant) as a component of the Network Service tariff for the subsequent period.

Section 7.4 contains sample tariff calculations for the Transmission Licensee to illustrate the points discussed above.

7.3 MARKET OPERATION FEE

The Transmission Company also performs the critical function of the Single Buyer, or Wholesale Market Operator, which currently includes the cash settlement process. It is very important to separate the various functions of the Transmission Company. Therefore, the costs related to this function must be accounted for separately and collected as a separate tariff from all market participants.

Costs include personnel, facilities, information systems, etc necessary to carry out this activity. Again, the Wholesale Market Account is MANAGED by the Transmission Company; however, it is NOT part of their revenues and expenses and, therefore, not part of this fee. The cost forecast should be presented to the ERA for review and approval. Since most of these costs are fixed, cost recovery should be accomplished by charging a fixed fee per month to the Wholesale Market Account. See Section 7.4 for a sample calculation.

7.4 SAMPLE TARIFF CALCULATIONS

To illustrate the methodology for determination of the Network Services and Market Operation Tariffs, an example is presented. Assume that the Transmission Company presents the following financial statements (with associated backup materials and cost allocations for the two separate activities) as a forecast of the future 12-month period as shown in Exhibit 7.1.

Exhibit 7.1 Financial Information for Transmission Licensee

BALANCE SHEET (millions Tg)		
Assets		
Current Assets		
Cash	50	
Spare Parts	300	
Accounts Receivable	700	
Total Current Assets		1,050
Fixed Assets		
Cost	14,000	
Accumulated Depreciation	3,000	
Net Fixed Assets		11,000
TOTAL ASSETS		12,050
Liabilities and Equity		
Current Liabilities		
Accounts Payable	300	
Salaries Payable	100	
Taxes Payable	50	
Short-Term Debt (8%)	300	
Total Current Liabilities		750
Long-Term Debt (6%)		3,000
Equity		8,300
TOTAL LIABILITIES AND EQUITY		12,050
INCOME STATEMENT (millions Tg)		
Revenue (Current Tariffs)		3,500
Operating Expenses		
Salaries	1,400	
Employee Related benefits	500	
Depreciation	467	
Current Maintenance	400	
Other Operating Expenses	105	
TOTAL OPERATING EXPENSES		2,872
Non-Operating Expenses		
Short-Term Interest Expense	24	
Long-Term Interest Expense	180	
Taxes	20	
		224
NET INCOME		404

For purposes of this example, assume that the Transmission Company is proposing a return on equity of 9%, resulting in a Return on Investment of 8.2 % as shown in Exhibit 7.2.

Exhibit 7.2 Return on Investment Calculation

	RETURN ON INVESTMENT:				
Investment:					
	Fixed Assets			14,000	
	Accumulated Depreciation			(3,000)	
	Working Capital				
		Current Assets		1,050	
		Current Liabilities		(750)	
		Short-Term Debt		300	
		Net Investment			11,600
Cost of Capital:					
		Amount	**Percent**	**Cost (%)**	**Weighted Cost**
Long Term Debt		3,000	26%	6%	1.6%
Short-Term Debt		300	3%	8%	0.2%
Equity		8,300	72%	9%	6.4%
	TOTALS	11,600	100%		8.2%
Return on Investment:					
Investment (Rate Base)					11,600
Rate of Return					8.2%
Return on Investment					951

The Transmission Company, as part of the tariff submission, must provide an allocation of costs to the Network Services and Wholesale Market Operation functions, enabling the determination of a revenue requirement for each of those functions, as shown in Exhibit 7.3.

Exhibit 7.3 Revenue Requirements

	REVENUE REQUIREMENT (millions Tg)	Total	Network Services	Market Operation
I.	**Operation and Maintenance Expense**			
	Salaries	1,400	1,250	150
	Employee Related benefits	500	446	54
	Current Maintenance	400	400	0
	Other Operating Expenses	105	80	25
		2,405	2,176	229
II.	**Depreciation**	467	425	42
!!!.	**Taxes**	20	20	0
!V.	**Return on Investment**	951	866	85
	TOTAL REVENUE REQUIREMENT	**3,843**	**3,488**	**355**

With the revenue requirements determined for each function, the next step is to determine the Network Services Tariff and Wholesale Market Operation Fee as shown in Exhibit 7.4.

Exhibit 7.4 Tariff Calculations

TARIFF CALCULATIONS		
Energy Balance Forecast (MWH):		
Purchases from Generators		2,200,000
Net Import		100,000
	Total energy into the CES	2,300,000
Sales to Distribution Companies		2,215,000
Transmission Losses		85,000
Network Services Tariff		
Revenue Requirement (Millions Tg)		3,488
Transmission System Output ((MWH)		2,215,000
Tariff (Tg/kWh)		**1.57**
Market Operation Fee		
Revenue Requirement (Millions Tg)		355
Monthly Fee (Thousands Tg)		**29,596**

The calculations show that, in order to recover the revenue requirement for network services, a tariff of 1.57 Tg per kWh must be applied to each kWh delivered to the distribution licensees. To recover the revenue requirement for market operation, a fee of 29,596,000 Tg must be charged per month.

8. TARIFF METHODOLOGY FOR DISTRIBUTION AND RETAIL SUPPLY LICENSEES IN THE CES

8.1 OVERVIEW

Each of the Distribution Entities in the Central Electricity System (CES) currently holds two licenses to perform the basic functions of Electricity Distribution and Regulated Retail Supply. In the future, as the market evolves, the Energy Law provides for the introduction of Unregulated Suppliers that would procure distribution services from the Distribution Licensees and sell to retail consumers at unregulated tariffs. It is, therefore, prudent to separate the costs of the current distribution entities into the two licensed activities as follows:

- Distribution Services (often referred to as the Wires Business), and
- Retail Supply

Each Licensee must allocate its costs to the two licensed activities using a rational, consistent method. Some cost elements are readily identifiable to a unique activity while others (administrative, employee benefits, etc must be allocated to the activities. This will allow separate revenue requirements to be determined.

8.2 THE DISTRIBUTION FUNCTION

The Distribution function includes the ownership, operation, and maintenance of the distribution infrastructure. Facilities (fixed assets) of the distribution system include lines, substations, transformers, service drops, and related equipment INCLUDING the customer meter. In addition, the distribution function includes the reading of the meter.

As discussed in Chapter 15, Cost of Service, customers should pay the operational costs and facilities costs that are necessary to provide service to them. On the other hand, they should not be assessed for costs that are required for other classes of customers. The primary determinant of the cost to serve a customer class is the voltage at which that class receives service. Therefore, we must further allocate the distribution revenue requirement to the three primary voltage classes:

- 35 KV
- 10 and 6 KV
- 400 volts

8.2.1 Allocating Distribution Costs to Voltage Classes

In order to determine the revenue requirement for each voltage class, cost elements must be analyzed and, where possible, directly assigned to voltage classes. For those costs that cannot be directly assigned, the Licensee must perform an allocation of the costs using a rational method on a consistent basis. Of course, there is not a single "correct" method of cost allocation. There are some general guidelines, however, that can be followed.

A. FIXED ASSET RELATED COSTS

Following are some general guidelines that can be used to assign fixed asset and related costs to voltage levels:

- A significant amount of fixed assets can be directly assigned to voltage classes.
  - Distribution lines are generally recorded in the fixed asset accounts based on their voltage.
  - Substations and transformers are generally recorded in the records based on their voltage. These facilities should be categorized based on the "low side" voltage (for example, a 35/10 KV transformer would be classified as 10 KV)
- Equipment not associated with specific voltages (vehicles, tools, buildings, etc.) could be allocated to voltages based on:
  - All other fixed assets
  - The distribution of employee salaries to voltage levels
  - The distribution of operating and maintenance costs to voltage levels
- Accumulated Depreciation can be analyzed specifically (along with the fixed assets themselves) or prorated based on the results of the fixed asset analysis.
- Depreciation expense can be analyzed specifically (along with the fixed assets themselves) or prorated based on the results of the fixed asset analysis.

B. OPERATING AND MAINTENANCE COSTS

Following are some general guidelines that can be used to assign operating and maintenance costs to voltage levels:

- Directly assign costs to voltage level where possible. Items such as replacement parts can be handled in this manner. Some salary costs can be directly charged to accounts associated with a specific voltage.
- Allocate salary costs based on estimates or surveys of the activities of employees
- Salary related costs such as benefits and taxes can be allocated based on salaries.
- General costs such as administration and support costs can be allocated based on overall salaries (or based on fixed assets if appropriate)
- Current maintenance is generally associated with facilities of a specific voltage.

8.2.2 Customer Meter Issues

Accurate, secure meters are a key ingredient in keeping commercial losses under control. The tradition of the customers owning their meters should definitely be discontinued. In a commercial environment, the Licensee must be assured that the device used to record sales and bill the customer is accurate and tamper proof. That objective cannot be accomplished if the customer owns the meter. The Energy Law of Mongolia states that the supplier should provide the meter, however, no action to accomplish this has been taken to date. Since the concept of meter ownership by the customer is so pervasive throughout Mongolia, any change should be initiated by the Energy Regulatory Authority. It has been recommended that ERA issue an order to the retail licensees requiring compliance with the Electricity Law. The order should state that each Licensee is to develop a plan to own and maintain all meters by 2007 and to implement the plan in stages. Such a program would require a significant investment on the part of the Distribution Licensees, but is essential to the future of the energy sector in a commercial environment. Distribution Licensees will have to develop expertise to maintain accurate meter record systems and to test and calibrate the meters. A 5-year transition will help to ease the burden as well as assurance by ERA that the cost will be included in tariffs. A summary action plan to accomplish this objective has been given to the ERA and the Government of Mongolia.

The Distribution Licensees should begin their meter program by first installing company owned meters at those customers that do not currently have meters and are, therefore, utilizing the “Open Tariff”. The objective should be to eliminate the open tariff option as soon as possible. Once all customers are metered, the Distribution Licensees will be in a better position to monitor and control commercial losses.

8.3 THE RETAIL SUPPLY FUNCTION

The Retail Supply function includes Customer Relations, Billing, Collections, Complaint Resolution, Marketing, etc. Since Bad Debt expense is related to collections, it is a component of cost associated with this function.

Collection of accounts receivable is a problem throughout Mongolia; however, the ERA has not yet included an allowance for bad debts in the tariffs. In the future an allowance for bad debt should be included in the retail supply tariffs to recognize that virtually no suppliers collect 100% of the amounts billed to customers. In accordance with International Accounting Standards, bad debt expense should be recorded to recognize that 100% of the revenue recorded in a particular period will not be collected and also to prevent the Accounts Receivable balance from being overstated. A recommendation has been made to the ERA for inclusion of Bad Debt expense in tariffs, along with a methodology to implement it. (See Appendix E)

The Retail Supply revenue requirement can be recovered in a variety of ways. The ideal way is to perform an analysis of the retail supply cost elements and allocate the revenue requirement to customer classes. Since we are dealing here with customer related costs, the analysis is rather straightforward. Each customer class would then have its unique cost of retail supply. That can then be recovered based on a flat cost per month per customer (a “Customer Charge) or as part of the energy charge (in terms of Tg/kWh).

In the future, the ERA should require Retail Supply Licensees to perform cost analyses in order to be able to determine the cost to serve each customer class. In the near term, however, the total revenue requirement can be divided by sales to all customer classes and a uniform Retail Supply tariff (in Tg/kWh) applied.

8.4 SAMPLE TARIFF CALCULATIONS

To illustrate the methodology for determination of the Distribution and Retail Supply Tariffs, an example is presented. Assume that a combination Distribution / Retail Supply Licensee presents the following financial statements (with associated backup materials and cost allocations for the two separate licensed activities) as a forecast of the future 12-month period as shown in Exhibit 8.1.

Exhibit 8.1 Financial Statements of the Licensee

BALANCE SHEET
(millions Tg)

Assets		
Current Assets		
Cash	50	
Spare Parts	600	
Accounts Receivable	2,000	
Total Current Assets		2,650
Fixed Assets		
Cost	8,000	
Accumulated Depreciation	2,500	
Net Fixed Assets		5,500
TOTAL ASSETS		8,150
Liabilities and Equity		
Current Liabilities		
Accounts Payable	2,500	
Salaries Payable	100	
Taxes Payable	50	
Short-Term Debt (10%)	400	
Total Current Liabilities		3,050
Long-Term Debt (6%)		1,500
Equity		3,600
TOTAL LIABILITIES AND EQUITY		8,150

INCOME STATEMENT
(millions Tg)

Revenue (Current Tariffs)		6,000
Operating Expenses (excl Power Purchases)		
Salaries	2,500	
Employee Related benefits	600	
Depreciation	850	
Current Maintenance	700	
Bad Debt Expense	500	
Other Operating Expenses	615	
TOTAL OPERATING EXPENSES		5,765
Non-Operating Expenses		
Short-Term Interest Expense	40	
Long-Term Interest Expense	90	
Taxes	50	
		180
NET INCOME		55

For purposes of this example, assume that the Licensee is proposing a return on equity of 12%, resulting in a Cost of Capital (or Rate of Return) of 10.2% as shown in Exhibit 8.2. When this rate is applied to the Investment (or Rate Base), the resulting Return on Investment of 562 million Tg is determined.

Exhibit 8.2 Return on Investment Calculation

		RETURN ON INVESTMENT:		
Investment (mil Tg):				
	Fixed Assets		8,000	
	Accumulated Depreciation		(2,500)	
	Working Capital			
		Current Assets	2,650	
		Current Liabilities	(3,050)	
		Short-Term Debt	400	
		Net Investment		5,500

Cost of Capital:				
	Amount	Percent	Cost (%)	Weighted Cost
Long Term Debt	1,500	27%	6%	1.6%
Short-Term Debt	400	7%	10%	0.7%
Equity	3,600	65%	12%	7.9%
TOTALS	5,500	100%		10.2%

Return on Investment:	
Investment (Rate Base)	5,500
Rate of Return	10.2%
Return on Investment	562

As part of its tariff submission, the Licensee must also be required to provide an allocation of costs to the Distribution and Retail Supply activities, enabling the determination of a revenue requirement for each of the licensed activities, as shown in Exhibit 8.3.

Exhibit 8.3 Revenue Requirements by License Category

	REVENUE REQUIREMENT (millions Tg)	Total	Distribution	Retail Supply
I.	**Operation and Maintenance Expense**			
	Salaries	2,500	1,900	600
	Employee Related benefits	600	456	144
	Current Maintenance	700	650	50
	Bad Debt Expense	500		500
	Other Operating Expenses	615	462	153
		4,915	3,468	1,447
II.	**Depreciation**	850	725	125
III.	**Taxes**	50	45	5
!V.	**Return on Investment**	562	493	69
	TOTAL REVENUE REQUIREMENT	6,377	4,731	1,646

In order to obtain a distribution tariff for each voltage category, cost details must be provided by the Licensee as part of the tariff application. Assume that the Licensee presented a detailed voltage level cost analysis, summarized in Exhibit 8.4.

Exhibit 8.4 Voltage Level Cost Detail

Distribution Cost Detail (millions of Tg)	35 KV	10/6 KV	400 volt	Total
Fixed Assets	975	1,625	3,900	6,500
Accumulated Depreciation	293	488	1,170	1,950
Working Capital	50	75	150	275
Operating Costs:				
Salaries	190	380	1,330	1,900
Employee Related benefits	46	91	319	456
Current Maintenance	98	130	423	650
Other Operating Expenses	51	102	309	462
Depreciation	109	181	435	725
Taxes	7	8	30	45

We now have the information necessary for calculation of the Revenue Requirement for each voltage class as shown in Exhibit 8.5.

Exhibit 8.5 Distribution Revenue Requirements by Voltage

Distribution Revenue Requirements (Millions of Tg)					
		35 KV	10/6 KV	400 volt	Total
I.	**Operation and Maintenance**				
	Salaries	190	380	1,330	1,900
	Employee Related benefits	46	91	319	456
	Current Maintenance	98	130	423	650
	Other Operating Expenses	51	102	309	462
	TOTAL	384	703	2,381	3,468
II.	**Depreciation**	109	181	435	725
!!!.	**Taxes**	7	8	30	45
!V.	**Return on Investment:**				
	Fixed Assets	975	1,625	3,900	6,500
	Accumulated Depreciation	293	488	1,170	1,950
	Working Capital	50	75	150	275
	TOTAL	733	1,213	2,880	4,825
	Rate of Return	10.2%	10.2%	10.2%	10.2%
	Total Return on Investment	75	124	294	493
TOTAL REVENUE REQUIREMENT		**575**	**1,016**	**3,140**	**4,731**

Also as part of the tariff application, the Licensee must provide an energy balance by voltage level. That information will allow the determination of tariffs by voltage as summarized in Exhibit 8.6. The exhibit shows that customers receiving service at 35 KV should pay a Distribution Tariff of 1.08 Tg/kWh, based only on the cost of providing service at 35 KV. Those customers receiving service at 10 or 6 KV pay 3.3 Tg/kWh, consisting of a 35 KV component of 1.13 Tg/kWh and a 10/6 KV component of 2.17 Tg/kWh. The 35 KV component for these customers is higher than for 35 KV customers due to losses on the 10/6 KV system. The 400-volt customers pay a 12.83 Tg/kWh distribution tariff with a 35 KV component (1.32 Tg/kWh), a 10/6 KV component (2.53 Tg/kWh), and a 400-volt component (8.97 Tg/kWh).

Exhibit 8.6 Voltage Level Tariffs for Distribution

	35 KV	10/6 KV	400 volt
Energy Balance (MWH):			
Delivered to Voltage Level	550,000	490,750	408,666
Losses at voltage level	19,250	22,084	58,666
Deliveries from Voltage Level:			
To Customers	40,000	60,000	350,000
To Lower voltage levels	490,750	408,666	0
Total Deliveries	530,750	468,666	350,000
35 KV Revenue Requirement (mil Tg)	575		
35 KV Distribution Fee @ voltage level	1.08	1.13	1.32
10/6 KV Revenue Requirement (mil Tg)		1,016	
10/6 KV Distribution Fee @ voltage level		2.17	2.53
400 volt Revenue Requirement (mil Tg)			3,140
400 volt Distribution Fee @ voltage level			8.97
Distribution Tariff by voltage level	**1.08**	**3.30**	**12.83**

The Retail Supply Revenue Requirement of 1,646,000,000 Tg is shown in Exhibit 8.7 along with the calculation of the uniform Retail Supply tariff of 3.66 Tg/kWh, based on the total Customer sales of 450,000 MWH detailed in Exhibit 8.6.

Exhibit 8.7 Retail Supply Revenue Requirement

	Retail Supply Tariff Determination (millions of Tg)	
I.	**Operation and Maintenance**	
	Salaries	600
	Employee Related benefits	144
	Current Maintenance	50
	Bad Debt Expense	500
	Other Operating Expenses	153
	TOTAL	1,447
II.	**Depreciation**	125
!!!.	**Taxes**	5
!V.	**Return on Investment:**	
	Fixed Assets	1,500
	Accumulated Depreciation	550
	Working Capital	(275)
	TOTAL	675
	Rate of Return	10.2%
	Total Return on Investment	69
	TOTAL REVENUE REQUIREMENT	**1,646**
	Sales to all Customers (MWH)	450,000
	Uniform Tariff (Tg/kWh)	**3.66**

We now have tariffs designed to recover the Distribution revenue requirements for each voltage level and the Retail Supply revenue requirement based on a uniform price per kWh for all customers. To show that the tariffs are designed properly to recover the entire revenue requirement, Exhibit 8.8 was developed. It shows that when the distribution tariffs are applied to sales at each voltage level they recover the distribution revenue requirement of 4,731,000,000 and that the Retail Supply tariff recovers that revenue requirement of 1,646,000,000. The total costs of the Licensee of 6,377,000,000 are recovered, thereby providing a return on equity of 12%.

Exhibit 8.8 Recovery of the Total Revenue Requirement of the Licensee

	35 KV	10/6 KV	400 volt	TOTAL
Sales (MWH)	40,000	60,000	350,000	450,000
Distribution Tariff (Tg/kWh)	1.08	3.30	12.83	
Distribution Revenue (mil Tg)	43	198	4,490	**4,731**
Retail Supply Tariff (Tg/kWh)	3.66	3.66	3.66	
Retail Supply Revenue (Mil Tg)	146	219	1,280	**1,646**
Total Revenue (mil Tg)				**6,377**

8.5 INCENTIVE MECHANISMS

Distribution network entities are regulated in most countries as natural monopolies. Without competitive market forces to control quality of service and cost, the regulator must step in to provide the control. As discussed in Chapter 11, Performance Based Regulation, rate of return (or Cost Plus) regulation does not necessarily provide the Licensee with incentives to reduce costs, improve service levels, or to implement new, innovative programs. Performance Based (or Incentive) Regulation aims to overcome this deficiency.

Performance measures and incentives for Distribution Licensees should focus on key issues such as:

- Control of technical and commercial losses
- Adequate metering
- Quality of Service (frequency and duration of outages as well as power quality)
- Cost of operating and maintaining the distribution system

Technical and commercial losses are a significant source of inefficiency in the power sector. Technical losses are primarily due to the fact that the distribution systems were designed for higher loads (often using poor quality equipment) and when the loads dropped due to poor economic circumstances, the loss percentages increased. In ger districts, especially in Ulaanbaatar, high technical losses are often due to the uncontrolled growth of ger areas, with already poor infrastructure. Technical loss reductions often focus on resizing of transformers and the reconductoring of circuits, resulting in significant costs. The World Bank recognizes this and the proposed loan to Ulaanbaatar Distribution Network is addressing this need. Commercial losses caused by poor (or non-existent) metering, theft of electricity, and substandard meter reading, billing, and collection are more controllable by the Licensees. Losses are a measurable quantity and each licensee should establish reasonable targets to minimize the losses. The tariff process for Distribution Licensees so far has focused on the assumptions used for loss factors since they are a primary driver of the cost of service.

Cost of providing distribution system services is also an issue. When tariffs are changed, the media often cites poor cost control as an issue. It is, therefore important to provide the management teams of the Distribution Companies with incentives to control their costs. Remember, the ERA cannot control costs, they can only provide incentives for Licensees to monitor and control costs.

Since losses and costs are of primary concern at this time, it is recommended that Price Cap Regulation be applied to Distribution Licensees. The implementation could be as follows:

- The Licensee proposes a target loss factor that it feels it can achieve over the next 3 years. It also proposes a target cost of operations for that period.
- The ERA reviews the Licensee's proposal based on prior history and the initiatives being undertaken by the Licensee in the areas of technical and commercial loss reduction and cost management.
- The ERA sets the Distribution Network component of the tariff at a fixed level for a period of 3 years. One technique is to set the level at the midpoint of the ranges for losses and costs. For example, if current losses are 20% and the 3 year target is 16%, the loss factor would be set at 18%, providing the Licensee incentive to get to 18% as soon as possible and then to get below that to achieve a "profit". Cost control targets can be set to achieve productivity savings by having salary levels set at current levels and requiring the Licensee to offset salary increases with productivity savings. Of course, if new fixed assets were required to achieve technical loss reductions, the increased depreciation would have to be factored in. Also, adequate maintenance must be performed during the period as well, possibly at higher levels than in the past.
- In order to prevent the Licensee from achieving cost savings by reducing service levels to customers, the ERA should specify minimum service levels in terms of outages and power quality.

In the longer term, incentive mechanisms can focus more directly on quality of service issues. The System Average Interruption Frequency Index (SAIFI), a measure of the number of times an average customer is interrupted in a year, and the System Average Interruption Duration Index (SAIDI), a measure of the number of hours an average customer is out of service in a year, can be used for distribution Licensees. Such measures require that reliable data be collected and monitored over a period of time in order that targets can be developed.

9. *TARIFF METHODOLOGY FOR HEAT NETWORKS*

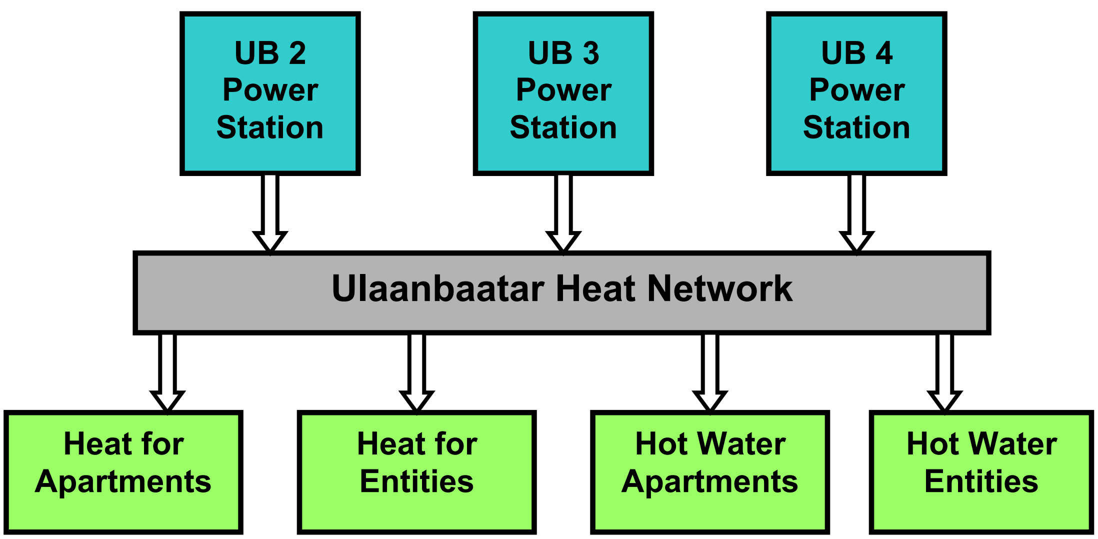
9.1 OVERVIEW

Central heat is definitely significant in the context of the overall power sector of Mongolia. More than 50% of the fuel utilized in power stations is estimated to be for heat production. Although heat tariffs are subsidized by electric tariffs, they still result in close to 25% of the retail revenue of the sector.

On a political level, heat tariffs are perceived to be more of a politically charged issue than those for electricity, due to the fact that the winter temperatures are so low and historically heat has been perceived as a service provided by the government at a low price to the public. To recognize the sensitivity, significant subsidies exist including a subsidy from electricity to heat managed at the power station level and then within the heat business, a subsidy from entities to households.

In Ulaanbaatar, the largest heat system, the market can be depicted as shown in Exhibit 9.1.

Exhibit 9.1 Market Structure for Heat in Ulaanbaatar



The financial structure in this system can be summarized as follows:

- The UB Heat Network currently incurs costs for heat purchased from the power stations on a per Gcal basis, amounting to approximately 80% of the total cost of service.
- Internal costs of the UB Heat Network to own, operate, and maintain the distribution network amount to 20% of total costs.
- UB Heat Network charges the customers using a variety of tariffs based on various measures including:
  - Heat consumption (Tg/Gcal)

- Area of structure heated (Tg/square meters)
- Volume of structure heated (Tg/cubic meters)
- Number of persons using hot water (Tg/person)

The economics of the other heat systems (Erdenet, Darkhan, Baganuur, etc.) are similar.

9.2 TARIFFS FOR HEAT PURCHASES FROM POWER STATIONS

The cost structure is such that the wholesale purchase of heat amounts to 80% of the total cost of service to the Heat Company. Purchases are based on the amount of heat supplied at the point of transfer from the power stations. Chapter 5 discusses in detail the determination of the price of heat to be charged by the power stations to the heat networks. The tariffs for the power stations will be set at the beginning of the year and the base price is not expected to change. As discussed in Section 5.4.4, a Fuel Cost Adjustment Mechanism is expected to be in place in order that each power station can adjust the prices it charges for electricity and heat output as the unit costs of coal, mazut, and fuel transportation change throughout the year. An example of the operation of the mechanism is contained in Exhibit 5.10. The fuel adjustment for heat output is expressed in terms of Tg/Gcal and represents an additional cost of wholesale purchases. When the wholesale purchase price of heat changes as a result of fuel cost adjustments, the distribution companies should immediately (within a month) be allowed to adjust all their various retail tariffs by a proportional amount.

The subsidy from electricity to heat is delivered at the power station level by reducing the revenue requirement for heat at power stations by approximately 40% and adding it to the electric revenue requirement. The base price for heat charged to the distribution company is, therefore, highly subsidized. It has been recommended that this subsidy be gradually reduced over time to (1) bring the cost of central heat closer to the true cost of supply and more in line with the cost of heat incurred by households not connected to the central heat system and (2) to relieve some of the pressure on electricity tariffs. Therefore, the wholesale price of heat can be expected to increase over time.

The ERA should treat the heat distribution companies as “middlemen” in the tariff process and allow them to pass along the costs incurred for wholesale purchases, which will increase over time due to reductions in the subsidy, fuel price changes, and general cost increases at the power stations.

9.3 HEAT NETWORK TARIFFS

In the newly restructured energy sector, the retail tariffs for heat are the result of the wholesale price for heat charged to the heat network plus the costs to distribute (or deliver) the heat to customers. Similar to the electric segment of the industry, each network will have a tariff to cover its costs of owning, operating, and maintaining the heat distribution network as well as the cost of billing, collection, and customer service.

To illustrate the methodology for determination of the Heat Network Tariff, an example is presented. Assume that a Licensee presents the following financial statements (with associated backup materials) as a forecast of the future 12-month period as shown in Exhibit 9.2. Of course, the information pertains only to the distribution portion of the business and, therefore, revenues and expenses exclude the wholesale cost of heat.

Exhibit 9.2 Financial Statements of the Licensee

BALANCE SHEET (millions Tg)		
Assets		
Current Assets		
Cash	500	
Spare Parts	300	
Accounts Receivable	2,000	
Total Current Assets		2,800
Fixed Assets		
Cost	40,000	
Accumulated Depreciation	4,500	
Net Fixed Assets		35,500
TOTAL ASSETS		38,300
Liabilities and Equity		
Current Liabilities		
Accounts Payable	5,000	
Salaries Payable	100	
Taxes Payable	50	
Short-Term Debt (10%)	150	
Total Current Liabilities		5,300
Long-Term Debt (5%)		19,000
Equity		14,000
TOTAL LIABILITIES AND EQUITY		38,300

INCOME STATEMENT (millions Tg)		
Revenue (Current Tariffs)		3,000
Operating Expenses (excl Heat Purchases)		
Salaries	400	
Employee Related benefits	100	
Depreciation	700	
Current Maintenance	600	
Bad Debt Expense	100	
Other Operating Expenses	65	
TOTAL OPERATING EXPENSES		1,965
Non-Operating Expenses		
Short-Term Interest Expense	15	
Long-Term Interest Expense	950	
Taxes	50	
		1,015
NET INCOME		20

For purposes of this example, assume that the Licensee is proposing a return on equity of 6%, resulting in a Cost of Capital (or Rate of Return) of 5.4% as shown in Exhibit 9.3. When this rate is applied to the Investment (or Rate Base), the Resulting Return on Investment of 1,805 million Tg is determined.

Exhibit 9.3 Return on Investment Calculation

	RETURN ON INVESTMENT:			
Investment (mil Tg):				
Fixed Assets			40,000	
Accumulated Depreciation			(4,500)	
Working Capital				
Current Assets			2,800	
Current Liabilities			(5,300)	
Short-Term Debt			150	
Net Investment				33,150
Cost of Capital:				
	Amount	Percent	Cost (%)	Weighted Cost
Long Term Debt	19,000	57.3%	5%	2.9%
Short-Term Debt	150	0.5%	10%	0.0%
Equity	14,000	42.2%	6%	2.5%
TOTALS	33,150	100%		5.4%
Return on Investment:				
Investment (Rate Base)				33,150
Rate of Return				5.4%
Return on Investment				1,805

Sufficient information is now available to calculate the Revenue Requirement for the Heat Network as shown in Exhibit 9.4.

Exhibit 9.4 Revenue Requirement for Heat Network

	REVENUE REQUIREMENT (millions Tg)	**Total**
I.	**Operation and Maintenance Expense**	
	Salaries	400
	Employee Related benefits	100
	Current Maintenance	600
	Bad Debt Expense	100
	Other Operating Expenses	65
		1,265
II.	**Depreciation**	700
III.	**Taxes**	50
!V.	**Return on Investment**	1,805
	TOTAL REVENUE REQUIREMENT	3,820

The revenue requirement of 3,820 million Tg will result in a significant tariff increase of 820 million Tg, representing 27% of current revenue (3,000 million Tg) for this activity. The Heat Network Tariff is then computed by dividing the Revenue Requirement by the estimated output. For example, if the output is forecasted to be 4,500,000 Gcal, the tariff would be 849 Tg/Gcal.

9.4 RETAIL TARIFFS FOR HEAT

The next step in the tariff process is to design tariffs to recover the revenue requirement. Given the extensive variety of tariffs, this is not an easy task. Exhibit 9.5 shows the tariffs for UB Heat Network approved by ERA on 28 June 2002. The reader will note that there are 8 “Industrial” tariffs and 3 household tariffs for heat and hot water. The units of measure range from heat received, to area and volume of the structure, to cost per person in the household or entity.

Exhibit 9.5 Retail Tariffs of UB Heat Network

	UBHDN: End-user tariffs	unit of measure	Tariffs
	Heat tariffs for industrial customers		
1	Heating for foreigners' apartments	Tg/m2	241
2	Heating for dormitories	Tg/m2	150
3	Heating for industrial customers	Tg/m3	170
4	Heating for basement, rest rooms	Tg/m2	160
5	Air conditioners	Tg/Gcal	5,000
6	Hot water for industrial customers	Tg/person	1,920
7	Hot water for technological use	Tg/Gcal	5,000
8	Heating (with metered customers)	Tg/Gcal	11,000
	Heat tariffs for households		
1	Heating for apartment blocks	Tg/m2	160
2	Hot water for households	Tg/person	520
3	Metered heating	Tg/Gcal	3,705

To allow the reader to make a valid comparison, the most commonly used tariffs were restated on an estimated basis to an equivalent Tg/Gcal measure and are shown in Exhibit 9.6. It should be noted that the composite retail tariff is approximately 5,000 Tg/Gcal.

Exhibit 9.6 Restatement of Tariffs to Equivalent Tg/Gcal (Estimated)

Customer class	Published Tariff	Equivalent Tariff Tg/Gcal
Apartment Heating - Unmetered	160 Tg/ M^2	1,896
Apartment Heating - Metered	3,705 Tg/Gcal	3,705
Heating for industrial - Unmetered	170 Tg/ M^3	11,693
Heating for industrial - Metered	11,000 Tg/Gcal	11,000
Hot water for households - Unmetered	520 Tg /Person	2,006
Hot water for industrial - Unmetered	1,920 Tg /Person	9,509
Hot water for industrial - Metered	5,000 Tg/Gcal	5,000

One can see the significant discrepancies between the various tariffs. The tariffs for Apartment heat are far below the average cost of 5,000 Tg/Gcal, with the metered customers paying twice as much as unmetered. This is a situation that should be corrected as soon as possible. Industrial tariffs for heat, both metered and unmetered are comparable at approximately 11,000 Tg/Gcal. Although the household tariff for hot water was increased by 30% in June 2002 (from 400 to 520 Tg/person/month), it is still far below the average cost of service. The Industrial hot water metered tariff is approximately at cost, while the unmetered tariff is far above cost.

9.5 RATIONALIZING THE HEAT TARIFFS

Ideally, heat customers should pay for heat and hot water based on the quantities they consume. That is the most equitable method and would allow customers that choose to conserve to save money. Heat metering is not currently in place to measure the Gcal used, especially at most households. For the near term, therefore, it is recommended that the current customer classifications be maintained. In the longer term, metering can be added, if warranted based on a financial analysis.

The ERA should implement a tariff rationalization plan that is based on the following concepts:

1. Gradually reduce the subsidy from electricity to heat at the power station level over a period of 5 years. Assuming that the subsidy is currently 40% of heat generation cost, a reasonable target would be to reduce the subsidy over the 5-year period to say 20%. This will leave a more reasonable subsidy, common in most countries. Of course, there will be cost increases at the power stations over this period of time as well. This will increase the wholesale price of heat to the heat networks, which will have to be included in retail tariffs.
2. Increase the unmetered tariff for households by approximately 15% per year (plus any cost increases) for the next 5 years, resulting in a doubling of that tariff, bringing it closer to the cost experienced by ger residents to heat their homes, but still below the cost of service. Apartments with heat meters are already paying almost as much as ger customers, so their tariffs should change by a much smaller percentage, say 5% plus cost increases.
3. Since heat tariffs for industry are already far above cost, increase them only slightly to reflect the higher wholesale cost of heat.
4. Hot water for households should be increased by approximately 15% per year (plus cost increases), approximately doubling that tariff over 5 years but still having it below cost.
5. The metered rate for hot water to industry is approximately at current average cost. It should be increased only slightly to reflect the higher wholesale cost of heat. The unmetered tariff is much higher and should probably be left flat.
6. Due to the significant tariff increases for households, a public information program must be put in place.

9.6 THE NEED FOR CONSERVATION

In most central heat systems, especially those existing in former Socialist countries, the most common method of heat regulation in apartments is to open windows. That obviously results in a waste of energy and natural resources. If apartments could control their heat utilizing valves on radiators (especially temperature sensitive valves), they would have the double benefit of being more comfortable and conserving energy. At the present time there is little economic incentive to invest in regulating valves. Metering heat usage would provide economic incentive, especially if heat tariffs were increased to the level of costs.

In the near term, the heat companies could provide incentive by offering those customers that install regulating devices a discount from the standard tariff. The ERA should encourage Heat Licensees to develop such a program and have the lower tariff approved.

9.7 THE IMPORTANCE OF A CONSUMER EDUCATION PROGRAM

The customers, politicians, and government officials must be educated on the need to increase heat tariffs. Appealing to them in rather simple terms that they can understand is critical. They must be made aware of the critical facts including:

- A typical ger household in Ulaanbaatar must pay at least twice as much to heat their residence with coal than a household living in an apartment. This is especially significant since, on average, ger households have less income than those in apartments. This is a message that the public can relate to.
- Heat tariffs are subsidized by having higher electricity tariffs. Reducing the subsidy is necessary to keep electricity tariffs from becoming too high. They should also be made aware that ger households subsidize apartments by having a subsidy from heat in their electricity tariffs.
- The public never likes a tariff increase, however, if they understand the situation, they will be more tolerant of the need for a change. Inform the customers of the significant bargain they are getting, especially considering the very harsh winters here in Mongolia. The comparative data for other country's heat tariffs, contained in the ERA Report for the year 2002, will allow the public to appreciate this more fully.

10. TARIFF METHODOLOGY FOR ISOLATED SYSTEMS

10.1 OVERVIEW

The Isolated Systems consist of those energy companies that are not connected to the Central Electricity System (CES), primarily the Eastern Energy System, Western Energy System, and Diesel Aimags. The isolated systems have unique characteristics that result in the cost to provide service to be significantly higher than the cost in the CES. Eastern Energy System is the only bundled system still operating in Mongolia, having a Combined Heat and Power Station, a transmission network providing electricity to Dornod and Sukhbaatar Aimags, an electric distribution and supply network serving Choibalsan and surrounding communities, and a heat distribution system serving Choibalsan city. Due in part to significant loss of the customer base, its costs are quite high. The Western Energy System (WES) purchases all its power needs from Russia (at a price negotiated by the Government of Mongolia) and transmits it to three local distribution/Supply companies. There are several Aimags that have diesel stations, which are costly to operate due to the cost of diesel fuel being based on world market prices.

Licensees in the Central Electricity System currently have tariffs that allow them to recover close to the full cost of providing service (excluding a return on equity) without the need for a direct subsidy from the State Budget. As a matter of public policy, the Government of Mongolia has decided that the customers of the isolated systems cannot afford to pay the full cost of providing service to them. This is due to the fact that the isolated energy suppliers have higher costs than the larger integrated Central Energy System and to the poor financial situations of the customers. This situation is common in many countries, including developed countries. In fact, the isolated systems are similar in many respects to rural electric entities in many countries. In July 2002, the ERA increased the tariffs of these small systems to the full cost of service level, since the Government of Mongolia had not provided any of the annual subsidies to those systems so far that year. Political pressure was so great that the Ministry of Finance and Economy finally approved a subsidy and the tariffs were reduced.

The ERA is also required by the Energy Law to “provide technical and methodological guidance to Regulatory Boards of aimags and the capital city”. The tariff methodology outlined in this document (especially the basic concepts) can also be utilized by those other regulatory bodies.

10.2 DETERMINING TARIFFS FOR THE ISOLATED SYSTEMS

The basic tariff process discussed throughout this report and utilized to determine tariffs for Licensees and Consumers in the CES is also valid for the Isolated Systems. It is as follows:

1. Determine the Revenue Requirement of the Licensee
2. Perform a Cost of Service to allocate that Revenue Requirement
3. Design tariffs based on the Cost of Service

For the isolated systems, steps 1 and 2 remain the same. Prior to designing the tariffs, however, the amount of the subsidy from the State Budget must be known. The Cost of Service of the Licensee must be recovered via two means, customer tariffs and the subsidy.

The ERA has been following the basic tariff process in the development of the tariffs for the isolated systems under its jurisdiction. The only enhancement recommended for the basic process is to develop an unbundled tariff for EES in order that the components (generation, transmission, distribution) can be determined. Such an unbundling would have made the determination of a tariff to serve the new zinc mine in Sukhbaatar Aimag more transparent as well as the tariff charged for energy sold on a wholesale basis to several Soums. Knowing the cost of power provided by the power station, the cost to transmit that power at high voltage, and the cost of distribution, can result in equitable tariffs for customers. The major enhancement recommended for these isolated systems is concerned with the integration of the tariff and subsidy approval processes discussed in Section 10.3

10.3 INTEGRATING THE TARIFF AND SUBSIDY PROCESSES

The decision to grant a subsidy has already been made by the Government of Mongolia. The issues to be addressed now are:

- The manner in which the amount of subsidy is determined
- How the subsidy is “Delivered”

The subsidy depends on (1) the costs of providing service and (2) the tariffs paid by customers. Therefore, the costs of providing service must first be determined and then reviewed for reasonableness. The logical organization to make this determination is the Energy Regulatory Authority, since they have expertise in the energy sector and are already performing this function in order to determine tariffs. The next step is to determine the tariffs that would be required to recover the cost. Assuming the full cost tariffs are too high for customers to afford, lower tariffs need to be developed. The subsidy is, therefore, the difference between the full costs and the costs allowed in tariffs.

If the amount of the subsidy is determined in an open manner, it will achieve the objectives of being:

- Quantifiable
- Transparent
- Formally Justified

The other objective of an effective subsidy is for it to be targeted. In an ideal situation, the subsidy would be delivered from the Government directly to those households and entities most in need of a subsidy. For practical reasons, however, it is most efficient to provide the subsidy to the Licensees.

The participants in the process include:

- The Licensees, with the mandate from the GOM to operate in a commercial manner
- The Energy Regulatory Authority (ERA) with the mandate from the GOM to balance and protect the interests of consumers and licensees
- The Ministry of Finance and Economy (MOFE) with the mandate from the GOM to review and recommend Budget elements for approval by the Ikh Hural.

A proposed Tariff and Subsidy Approval Process has been developed in order to rationalize the manner in which prices and subsidies for the isolated systems are determined, approved, and delivered. The intent is to preclude the gridlock that occurred during the summer and fall of

2002 as tariffs and subsidies were being decided upon. The proposed process includes the following ingredients:

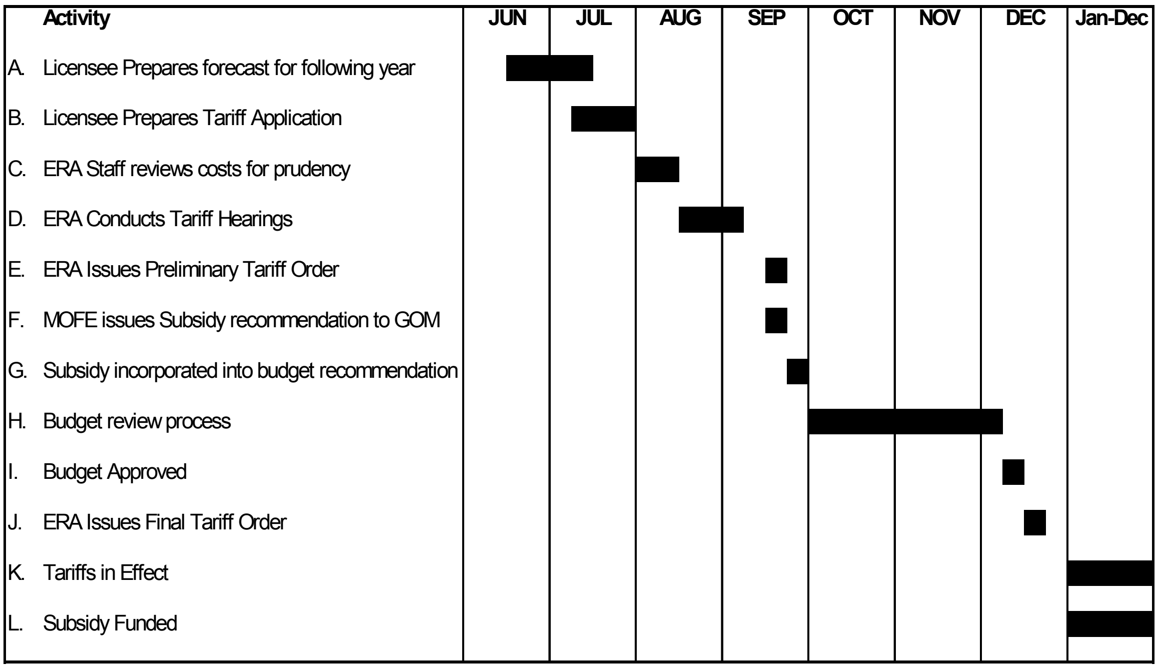
- The Licensee prepares a forecast for the following year of revenues and expenses as well as proposed tariffs and submits the information to the ERA.
- The ERA staff reviews the forecast for prudence and the ERA Board conducts hearings at which time MOFE participates as a party to the hearings.
- ERA produces a preliminary tariff decision and MOFE submits its recommendation for the subsidy amount as a Budget expenditure.
- After the budget is approved (in December), the ERA issues a final tariff order that produces tariffs equal to prudent costs less the approved budget subsidy.
- The subsidy is funded on a monthly basis during the following year.

Exhibit 10.1 contains a description of the proposed process and the activities and participants involved. Exhibit 10.2 displays the proposed process on a time line, since the timing of the entire tariff process needs to consider that the subsidy must be determined and approved in accordance with the time schedule of the State Budget.

Exhibit 10.1 Activities Required for Tariff and Subsidy Approval

Activity Description		Components
A. Forecast for the following year	1	Forecasted sales for each class of Customer
	2	Forecast of operating costs by component (fuel, salaries, etc)
	3	Operating costs separated by electricity and heat
	4	Interest expense
	5	Forecasted financial statements with revenue at existing tariffs
B. Tariff Application	1	Complete detailed Forecast (From A)
	2	Proposed Tariffs for each customer class
	3	Proposed Subsidy
	4	Deliver to ERA and Ministry of Finance and Economy
C. ERA Staff Review	1	Review all elements of forecast for reasobleness and prudence
	2	Prepare report to the ERA Board, MOFE, Licensee
	3	Include recommendation on reasobleness of forecast
	4	Include recommendation on tariffs for each class of customer
D. Tariff Hearings	1	ERA holds open hearings - MOFE, and other parties participate
	2	Licensee Presents its position
	3	ERA Staff presents its report
	4	MOFE presents its recommendation on amount of subsidy
E. ERA Preliminary Tariff Order	1	Tariff order issued considering input of all parties
	2	Tariffs equal to prudent costs less subsidy proposal
F. MOFE Subsidy Recommendation	1	Formal submission of subsidy request to the GOM
G. Subsidy put in budget submission	1	Specific line item for approval (to be funded quarterly in cash)
H. Budget Review Process	1	All parties (Licensee, ERA, MOFE) available to answer questions
I. Budget Approved	1	Amount of subsidy now finalized
J. ERA Issues Final Tariff Order	1	Final Tariffs equal to prudent costs less approved subsidy
K. Tariffs in Effect	1	New tariffs become effective 01 January
L. Subsidy Funded	1	Subsidy paid in cash: 1/12 each month

Exhibit 10.2 Tariff and Subsidy Approval Time Schedule



With the tariff and subsidy procedures integrated, the entire process can be carried out in a rational manner, accomplishing the objectives of the Licensees, the ERA, Ministry of Finance and Economy, and the Government of Mongolia. Preventing the gridlock that occurred in 2002 is critical.

11. PERFORMANCE BASED REGULATION

11.1 GENERAL

Rate of Return (or Cost Plus) Regulation does not necessarily provide the utility with incentives to reduce costs, improve service levels, or to implement new, innovative programs. Performance Based (or Incentive) Regulation aims to overcome this deficiency. If a pre determined performance measure has been met or exceeded, the Licensee is rewarded in the form of higher "Profits". If targets are not met, the Licensee is penalized, generally in financial terms (lower "Profits"). It is very important to remember that the Regulator should not be running the Licensees' businesses. The Regulator can provide the proper incentives, however, to allow innovative Licensee management teams to benefit from cost effective and customer oriented improvements.

Most Performance Based Mechanisms rely on financial incentives and disincentives to induce desired behavior by a regulated firm. The basic assumption, of course, is that Licensees have a profit motive. An important issue in many countries with government owned power sector entities is: "How can Performance Based Regulation be implemented for Licensees that are not driven by a strong profit motive?"

11.2 PRICE CAP REGULATION

One of the simplest forms of Incentive Regulation is Price Cap regulation, in which the regulator sets a given price for the output of an entity and thereafter it is up to the entity to manage effectively in order to provide the service (at some given level) and realize a profit. This method of regulation requires the application of good business management practices and a profit motive on the part of the entity. Very often, strategic investors prefer this type of regulation if they feel that the entity in which they are investing has significant opportunity for improvement and they do not want a regulator to pass all the savings due to cost reduction programs along to customers.

In the general case, the licensee is expected to live within the price cap for a period of time and to implement cost saving measures to partially offset inflationary pressures and to improve profitability. The licensee earns higher returns if it is successful and lower (or, possibly negative) returns if it is not successful. Investments will be made for new plant and equipment, maintenance programs, computer systems, meter reading technologies, etc. if the licensee feels that the cost of those investments will produce true cost savings. In other words, capital investment projects must provide a positive net present value or an internal rate of return in excess of the cost of capital. In this manner, utilities are encouraged to manage their businesses in the same manner as unregulated entities.

In some cases, the price cap may be in place for a period of several years. Over that period of time, unforeseen events can occur and very often there is a provision for factoring in external factors. A common method used is to allow the price cap in a future period to be adjusted for inflation, productivity improvements, and selected significant external factors. The price cap may be expressed as follows:

$$P_1 = P_0 \times (1 + (i - x)) + z$$

Where:

P_0 = Price cap for year 0

P_1 = Price cap for year 1

i = inflation rate

x = a productivity factor expressed in percent

z = an adjustment for selected major external events over which the entity has limited control such as:

- New tax regulations
- New environmental regulations
- Major storms and other natural disasters

The entity management must control its costs within the level of inflation, offset in part by productivity improvements. The risk of the identified external events is shifted to the customers by the inclusion of the z factor, which may also be used to incorporate fuel cost and other adjustment mechanisms. Many regulators feel that such a mechanism provides the proper incentives for innovative management while allowing for reasonable increases in price that would occur in an unregulated market.

The key to effective use of such a mechanism is to properly specify the inflation, productivity, and external factors in a manner that is fair to both the supplier and the customer. Of course, the regulator must also monitor the level of service provided to insure that the entity is not sacrificing quality of service in order to keep costs below the cap. Also, as previously discussed, the entity must have a profit motive in order for such a mechanism to be effective.

11.3 OTHER PERFORMANCE BASED METHODS

A major objective of regulation is to strive for high quality service at the lowest possible price to consumers. An effective way to facilitate that is for the regulator to establish performance standards and allow entity management to operate the business within those parameters. If they are successful, entities will be rewarded, otherwise they will incur financial penalties.

A logical process for an effective performance based incentive system would involve the following steps:

1. Identify Goals

2. Develop Initiatives to Meet the Goals

3. Develop Measures of Performance

4. Measure Progress

5. Implement the Reward or Penalty

Each of those steps will be discussed in detail.

11.3.1 Identify Goals

It is important to establish goals that represent a level of performance that is beneficial for the customers. Goals should be based on what is really important and should be:

- Meaningful
- Quantifiable
- Measurable
- Achievable
- Established by the personnel or entity responsible for achieving the goal
- Acceptable to the Stakeholders:
    - Licensees
    - ERA
    - Government
    - Customers

Goals fall into various categories such as:

- Financial (economic)
    - Cost Reduction
    - Improvements in Productivity
    - Enhanced Cash Flow
    - Minimization of Tariff Levels
- Customer Service
    - Reduction in frequency and duration of outages
    - Improved service restoration time
    - Enhanced field service
    - Prompt resolution of complaints
    - Maximum hours of service

Some goals may be conflicting such as cost reduction and improved reliability. That is where innovative management becomes important. The proper balance must be achieved and that is often referred to in the management literature as a Balanced Scorecard.

Let's focus on the major cost elements to find opportunities for financial goals.

The primary focus of cost reduction opportunities should be on power supply costs, comprising a significant portion of overall costs. Opportunities may include:

- Reduction of Commercial Losses
- Reduction of Technical Losses
- Reduction in Station Use
- Improvement in fuel rates
- Availability and/or Capacity Factors of power stations
- Reduction in the number of unmetered customers

All parties must recognize that, in order to achieve the savings, an increase in Capital, Operating, and Maintenance costs may be necessary for:

- Metering equipment
- Upgrade of facilities (Generation, Transmission, Distribution)
- Employee costs (salaries, training, etc.)
- Computer System development or enhancement

The primary focus of Customer Service improvement opportunities should concentrate on issues of significant concern to Customers. Why not ask Customers for their opinions? Some opportunities to improve customer service may include:

- Reliability as determined by:
  - Frequency of outages, often measured by a System Average Interruption Frequency Index (SAIFI)
  - Duration of outages, often measured by a System Average Interruption Duration Index (SAIDI)
  - Service restoration time
- Complaint Resolution
- Field Service issues
- More hours of power available to customers
- Accuracy of meters

The ERA is encouraged to involve all the Stakeholders by obtaining their input on what is important to them and to make the process an interactive one. Again, balance is important as far as cost cutting vs. customer service objectives are concerned.

Once input is obtained from the ERA, the Licensee should propose the goals upon which it will be measured. Remember, the licensee is the entity that will have to meet the goals and, therefore, it is important that the company take “Ownership” of them. If licensees do not “Buy In” to the goals, they will not be achieved.

11.3.2 Develop Initiatives to Meet the Goals

Once the goals are established, the licensees should develop the initiatives to achieve the goals since this is an internal management issue. In order to achieve the objectives, various resources may be required in the form of:

- Capital Improvements
- Operating and Maintenance Costs
- Personnel

11.3.3 Measures of Performance

All parties must recognize that it is difficult to develop meaningful and effective measures. Licensees should be required to propose measures that are appropriate to their operating situation, cost structure, and customers. They know their business best and will have to make improvements based on those measures. At the same time, the resources required to achieve the performance level should be communicated.

The proposal should be presented to ERA and made available to interested parties (similar to a tariff application). After a review process that is, hopefully, interactive, the ERA should determine the performance measures to be used. The measures should incorporate an expected value (or range in some cases) that the initiative is expected to produce, given the needed resources.

For long-term initiatives (such as reduction of commercial losses) interim measures should be established. For example, a 2-percentage point reduction in year 1, a 4-point reduction in year 2, etc could be used as targets.

11.3.4 Measuring Progress

Progress should be measured periodically; monthly is common in a utility situation. Licensees, however, may want to measure progress more frequently for internal control and employee motivation. The licensee should communicate the actual performance to ERA and other interested parties via a short, meaningful report.

At the end of a given period (annual in many cases, or at certain milestone dates) the licensee should report progress against the goal. In addition to the raw data, commentary should be provided to inform the outside parties. The reporting should also include information on implementation costs.

11.3.5 Implementing the Reward / Penalty

The objective is to provide incentive to the licensee, its management team, and employees to achieve the objectives. Most mechanisms are based on financial incentives and rewards are often in the form of:

- A higher return on equity

- An additional allowance in the tariff equal to a % of costs saved
- A fixed monetary amount for meeting a target.

Penalties could be lower returns on equity or other tariff reductions to recognize that goals were not met.

11.4 MOTIVATING BEHAVIOR

A key issue involving cost reduction programs is often how the savings are allocated to the Stakeholders, including customers, the Licensee, and its owners managers, and employees.

In the case of State Owned Entities, however, we come back to the question:

> *How can Performance Based Regulation be implemented for Licensees that are not driven by a strong profit motive?"*

Motivating Behavior is a key issue and, if the entity itself is not driven by financial motives, the employees generally are. If employee compensation can be linked to incentive measures, a Bottom-Up approach can be used. Incentive Compensation mechanisms are currently being used by many licensees. The ERA should encourage licensees to develop and implement effective incentive compensation systems for employees. This includes, of course, allowance of the cost of those programs (hopefully resulting in increased labor costs due to goals being met) in tariffs. Regardless of whether employees receive incentive compensation, it is very important that they realize that it is not the objective of incentive regulation to reduce costs merely by cutting jobs. Employees should be part of the solution to increasing productivity and levels of service. Don't give them reason to sabotage a performance measurement and incentive system because they are concerned that achieving objectives will result in loss of jobs.

11.5 THE ROLE OF THE REGULATOR WITH A PBR SYSTEM

Performance Based Regulation places the responsibility for effective technical, commercial, and financial performance on the Licensees, not the Regulator. From a business management point of view, the Licensee is the most appropriate entity to manage cost and performance, within the constraint of market forces. The role of the Regulator (in this case ERA) changes significantly from being an "enforcer" to providing oversight and monitoring. That is why Performance Based Regulation is often referred to as a more "hands off" form of regulation.

12. SUBSIDIES

12.1 GENERAL

The dictionary defines a Subsidy in general as “a grant or gift of money”. In the context of Governments, a subsidy is “a grant by the government to a private person or company to assist an enterprise deemed advantageous to the public”. From an energy system point of view, subsidies can exist between

- Governments and Licensees
- Governments and the customers
- Licensees and customers
- Classes of customers

In general, subsidies are utilized to

- Shift cost responsibility from consumers to the government, from one consumer class to another (Residential to Industrial or Business), from consumers to investors, or from one region to another.
- Accomplish social goals such as Rural Electrification, small business development, or to address the issue of poverty.

From a pure theoretical economics point of view, subsidies should not be necessary. From a practical and social responsibility point of view, however, they are needed and should be considered by regulators as a fact of life. The important thing is for regulators to make sure they are effective. Effective subsidies generally are:

Quantifiable

In order to make informed decisions, the regulator, the Government, and customers must be able to determine the amount of the subsidy. If a subsidy cannot be quantified, none of the parties know what they are dealing with and the other criteria discussed below cannot be met.

Transparent

Once a subsidy can be quantified, it is possible to make it transparent. Transparency starts with the tariff process by determining the revenue requirement, performing a cost of service, and designing tariffs in a manner that all parties to the process can understand.

Formally Justified

The responsibility for justification should rest with the government. Having the proposed subsidy being quantified and transparent, means that the justification can be made in a more informed manner.

Targeted

Effective subsidies must be delivered to the intended recipients. In the case of subsidies intended for poor customers, if there is a social service agency that has identified the people in need, the regulator's job is made easier. If the government is the entity that is requiring the subsidy and it can be convinced to deliver it directly to the intended recipients, then this is the most effective method and the tariff process does not have to deal with the issue. This is not the situation in most cases and the regulator must find a way to target the subsidy. In some cases, assumptions must be made in order to target a subsidy. In the case of lifeline tariffs, the assumption is often made that low use customers are also poor. This may not necessarily be the case, but is an assumption made for expediency. A similar situation may exist in the case of senior citizen (Pensioners) tariffs.

Part of Comprehensive Reform

Governments often grant subsidies to certain groups of individuals or businesses. The question to ask is whether the subsidy is in line with other government programs or objectives.

Non-By Passable

If the government or the regulator determines that certain customer classes should subsidize other classes, then it important that the subsidy mechanism be designed in a manner that the classes responsible for providing the subsidy are not permitted to shirk that responsibility.

Subsidy Mechanisms can include

- Cross subsidies between users
    - Uniform tariffs over the entire service area despite the fact that the cost to serve certain areas may differ.
    - Subsidies between licensed activities (for example, electricity and heat).
    - Subsidies between classes of customers
    - Lifeline tariffs, allowing low-income consumers the opportunity to purchase sufficient electricity to provide a minimal standard of living. The price per kWh is generally set below cost at an amount that the eligible consumers can afford. The obvious question is "Which other customers should be required to cover the shortfall?"
- Direct transfers to consumers (vouchers). This allows the subsidy to be more directly targeted.
- Direct government funding of enterprises.
- Direct government funding of inputs (such as fuel subsidies, low cost loans, etc.).
- Lower rates of return. The Licensee is, therefore, subsidizing the customers. Of course, if the Licensee is government owned, then the government itself is providing the subsidy in an indirect manner by allowing the entity to deteriorate in a financial sense.

12.2 SUBSIDY ISSUES IN MONGOLIA

What "Subsidies" exist in the Mongolian Power Sector? Exhibit 12.1 provides an overview of the various subsidies, and the effects of those subsidies.

Exhibit 12.1 Subsidies in the Mongolian Power Sector

Subsidy	Effect
Electricity to Heat	Heat tariffs artificially low (½ of cost) Electricity Tariffs higher by 14 billion Tg
Similar tariffs for high and low voltage customers	High voltage tariffs too high Low voltage tariffs too low
Uniform Electric Tariffs in the CES	Erdenet tariffs too high UB & Darkhan tariffs too low
No return on equity for energy companies	The owner of the companies (the GOM) subsidizes customers
Heat tariffs for entities much higher than for households	Although all heat tariffs are low, household tariffs are especially so
Direct Subsidies from the Budget to the Isolated Systems	The GOM is subsidizing customers of the Western and Eastern Systems and the Diesel Aimags
Coal prices controlled by the GOM	Coal companies may be subsidizing electricity and heat customers
Railroad tariffs controlled by GOM	Transportation of coal may be subsidized by Transportation Sector
Large State Owned enterprises allowed to accumulate large arrears	Energy Companies incur losses
Household theft of electricity is tolerated	Tariffs of paying customers are higher due to commercial losses

12.3 RECOMMENDATIONS CONCERNING SUBSIDIES

As previously discussed, subsidies are not necessarily bad. The important thing for the GOM and the ERA to do, however, is to make sure that the subsidies that exist are transparent, effective, and in line with Government Policy. To make informed decisions, policy makers should be aware of the magnitude of the subsidy and its intended purpose. The Energy Law of Mongolia is quite clear that tariffs should be based on the cost of providing service to the various customer classes. See Chapter 3 for a discussion of the law. Although there is a legal basis to eliminate subsidies, those that have been in place for long periods of time are difficult to remove since customers and governmental officials are accustomed to them. It is also important to ascertain the social and cross-sector effects of altering subsidies so that the GOM can make the best decisions for the country while balancing social concerns against sound economic policy. It is, therefore, important to work to change public perception.

12.3.1 Heat Tariff Issues

The subsidy from electricity to heat is a good example. A typical ger household in Ulaanbaatar must pay at least twice as much to heat their residence with coal than a household living in an apartment. This is especially significant since, on average, ger households have less income than those in apartments. However, decision makers and politicians believe that there is massive public resistance to increased central heat tariffs. The need for an effective public education program is obvious. The public never likes a tariff increase, however, if they understand the situation, they will be more tolerant of the need for a change. In most countries, heat tariffs are subsidized by electric tariffs. ERA, however, should gradually reduce the subsidy in order to take the pressure off electricity tariffs. Remember – Heat tariffs are currently a real bargain for consumers, especially considering the very harsh winters here in Mongolia.

Another aspect of heat tariffs is that the tariff for entities, expressed as Tg per cubic meter, results in a higher cost to heat an equivalent volume of space than the household tariff, expressed in Tg per square meter. For example, the heat tariff for entities in UB is 170 Tg per cubic meter while the household tariff is 160 Tg per square meter. Assuming that an average ceiling height in an apartment is 2.5 meters, if the household tariff was expressed in cubic meters, it would be 64 Tg per cubic meter. The result is that heat tariffs in total are too low and the household tariff is especially low. Public education should begin immediately so the heat tariffs can be gradually increased over time (say 10-15% per year in addition to any cost increases).

12.3.2 Electric Tariff Issues

In this report, the importance of performing a study of the cost to serve customers at the various voltage levels (the most significant driver of costs) has been stressed. Such a study will indicate that tariffs for customers served at the higher voltages are too high while those for lower voltages are too low. Once the Licensees prepare the cost studies, the ERA will have information to restructure the tariffs, again, gradually over time to reflect cost differences. See Chapter 15 for more information.

Recommendations made concerning Wholesale Market Pricing (See Chapter 6) will correct the problem of the inherent subsidies due to uniform tariffs in the CES. In the future, customers in UB, Darkhan, Erdenet, and Baganuur will pay the specific cost to serve them, considering the various cost components. At the present time, for example, since the UB Distribution and Retail Supply tariffs are higher than the Erdenet tariffs and the UB technical and commercial losses are higher than those of Erdenet, the wholesale price of power charged to UB is less than that to Erdenet in order to maintain a uniform retail tariff. That subsidy from Erdenet to UB will be eliminated when the Wholesale Market pricing is changed. (See Chapter 6)

The Government of Mongolia (as the owner of the energy companies) can be considered to be subsidizing electricity and heat since there is not a return on equity included in tariffs (See Chapter 4). Many countries make the public policy decision to do this to keep tariffs low. This is not a major problem, however, over time the ERA should include some return on equity in tariffs, especially once private investors enter the system.

12.3.3 Subsidies for Isolated Systems

As a matter of public policy, the Government of Mongolia has decided that the customers of the isolated systems cannot afford to pay the full cost of providing service to them. This is due to the fact that the isolated energy suppliers have higher costs than the larger integrated Central Energy System. This situation is common in many countries, including developed countries. In fact, the smaller systems (Western, Eastern, and Diesel Aimags) are similar in many respects to rural electric entities in many countries. In July 2002, the ERA increased the tariffs of these small systems to the full cost of service level since the Government of Mongolia had not provided any of the annual subsidies to those systems so far that year. Political pressure was so great that the Ministry of Finance and Economy finally approved a subsidy and the tariffs were reduced.

The decision to grant a subsidy has, therefore, already been made by the Government of Mongolia. The issues to be addressed now are:

- The manner in which the amount of subsidy is determined
- How the subsidy is “Delivered”

See Chapter 10 for a discussion of the proposed tariff and subsidy approval process for the isolated systems.

12.3.4 Non-Payment Issues

By tolerating the situation where certain customers receive service but do not pay for it, the Government of Mongolia is providing an indirect subsidy to those customers. The subsidy is in the form of losses of the companies (that are State Owned) and a waste of natural resources. Electricity payments are not the appropriate tool to use to solve problems in other industries. If other industries feel they need subsidies, then they should establish their own, hopefully transparent and direct subsidy mechanism. If the government concurs that a subsidy is necessary to achieve its policy goals, including protection of certain industries or retention of jobs in those industries, then it should fund the subsidy in a more direct manner. The most blatant case of nonpayment the author has experience with in Mongolia is that of Hotol Cement Chalk Company. That firm has been bankrupt since it was turned over to the State and owes the Darkhan Selenge Electricity Distribution Network over 1.6 Billion Tg in unpaid electricity bills. Repeated attempts to disconnect the customer have resulted in significant political pressure being put on the Distribution Company to reconnect the customer. This situation must end.

In Mongolia, there seems to be a high level of tolerance for households that steal electricity. Although the Energy Law is quite clear that households stealing electricity should be required to pay penalties and disconnected if they do not pay, uniform practices are not followed. Part of the reason is that there seems to be a perception that, if people are poor, stealing of electricity is tolerated since they feel they are obtaining the power from the State. Public education programs should be aimed at changing this perception and getting the point across that people are actually stealing from their neighbors since higher commercial losses increase tariffs for those who do pay. The ERA is working on a uniform rule dealing with energy consumption and that can help solve some of the problem, especially in the area of uniform disconnection policies.

12.3.5 Lifeline Tariff

A Lifeline Tariff is being proposed (see Chapter 13). Such a tariff can be perceived to provide a subsidy to low use households at the expense of higher use households. As long as the subsidy is quantified and funded within the household tariff class, such a subsidy is very acceptable, and commonly used in other countries. A major benefit of such a subsidy is that it provides an effective means to be able to adjust tariffs to their proper level while at the same time keeping the low use customer tariffs low, a major selling point when dealing with politicians who are afraid of public pressure when tariffs are increased.

13. LIFELINE TARIFFS FOR HOUSEHOLDS

13.1 BACKGROUND

Throughout Mongolia, there is a very serious concern about the number of households living in poverty. The Government and many international donors and NGOs are working to improve the economic situation of the country. In its "Strategy for Sustainable Development of the Energy Sector", the Government of Mongolia stressed the importance of having a lifeline tariff to allow poor customers to procure needed amounts of electricity. Politicians and government officials tend to resist restructuring of tariffs to bring the household tariffs closer to the cost to serve, primarily due to their concern about ability to pay. For these reasons, the tariff methodology must address the needs of low-income customers.

Mongolia is not alone in its concern for low-income customers to be able to have a basic amount of electricity at a price they can afford. Throughout the world, governments and regulators struggle with these issues. There is general consensus that low-income households should be subsidized. The issue is the manner in which the subsidy should be determined and delivered. Effective subsidies (discussed in Chapter 12) must be delivered to the intended recipients. In the case of subsidies intended for poor customers, if there is a social service agency that has identified the people in need, the regulator's job is made easier. If the government is the entity that is requiring the subsidy and it can be convinced to deliver it directly to the intended recipients, then this is the most effective method and the tariff process does not have to deal with the issue. The Government of Mongolia does not have the financial resources to fund a low-income subsidy and, therefore, the energy sector must find a way to address the problem. It is up to the ERA to design and target the subsidy. In most cases, assumptions must be made in order to target a subsidy. In the case of lifeline tariffs, the assumption is often made that low use customers are also poor. This may not necessarily be the case, but is an assumption made for expediency.

The author has been struggling with this issue over a period of several years working in Mongolia. Discussions have been held with people throughout the sector, government officials, advisors working in other sectors, and Mongolian citizens. The primary difficulty is to define which customers are in need of a subsidy. As part of the commercialization work being performed, the advisor developed a discussion document, initially to present to Eastern Energy System, and subsequently discussed with the Staff of the ERA and others. That document is contained in Appendix B.

13.2 SIGNIFICANT CONSIDERATIONS

A Lifeline Tariff is being proposed (see Chapter 16, Tariff Design). Such a tariff can be perceived to provide a subsidy to low use households at the expense of higher use households. As long as the subsidy is quantified and funded within the household tariff class, such a subsidy is very acceptable, and commonly used in other countries. A major benefit of such a subsidy is that it provides an effective means to be able to adjust tariffs to their proper level while at the same time keeping the low use customer tariffs low, a major selling point when dealing with politicians who are afraid of public pressure when tariffs are increased.

The major considerations in designing a special tariff for low-income customers include:

1. Targeting the recipients
2. Determining the amount of the subsidy
3. Determining consumption limits to prevent abuse
4. Designing the tariff

Targeting the recipients is the most difficult task. The Government of Mongolia does not have a social service agency charged with identifying people in need. That is a significant deficiency. Countries that have a viable social service agency are able to use the criteria of the agency to define the intended recipients. The regulator's job is therefore much easier. In addition, due to the lack of available government information (through the tax system or other means) on household incomes (due to the transient nature of the population, the existence of a significant underground economy, etc.), the ERA must develop its own target population. Several options were explored to arrive at a possible solution.

One alternative is to define Pensioners as low-income. The advantage here is that either a person is on the pension rolls or not, making the identification rather straightforward. Given the level of pensions in Mongolia, most Pensioners would be considered poor, assuming they have no significant other income. Due to the low level of pensions, however, many Pensioners either live in their children's residences or adult children live in Pensioners' homes, meaning that the total household income may not be low. Also, the definition of a pensioner's household may be difficult to determine.

Another easy group to identify are the ger households. Although not all ger customers are poor, a high percentage of them probably are. Another (somewhat unrelated) issue is that, since electricity tariffs include a subsidy for central heat, which is not available to ger residents, a case can be made to have a lower tariff for them. Conversely, since the technical and commercial losses are abnormally high in ger districts, their tariffs are probably too low. Let's have the Cost of Service and loss reduction programs solve those issues.

Another option discussed was to have various local government or community leaders identify poor households. Community officials at the Khoroo and Bog levels were specifically mentioned. The advantage here is that local officials are closest to the people and generally know them, putting them in a position to know the financial situation of households. There is, however, a significant potential for abuse with such a system. Since local officials are not a cohesive group, their decisions may be quite inconsistent from district to district. Also, they may favor certain households that are not poor.

The bottom line is, without a viable definition of poor households by a reputable governmental agency, the regulator is left in a difficult position. Trying to identify poor households without having reliable data on household income is extremely difficult. Mongolia does not want to get into the position of many of the ex Socialist countries, such as Ukraine, which has 27 categories of "Privileged" electricity customers with tariffs ranging from 0% to 75% of the normal tariff. In that country, a high percent of households were considered privileged, including judges and police.

Without income data, the amount of the subsidy is also difficult to determine. Significant judgment is required.

Whatever the definition of eligible customers, it is important to establish limits on the amount of energy they can acquire at the reduced price. Consumers should not be allowed to consume excessive amounts of energy at a low-income tariff.

13.3 RECOMMENDED TARIFF DESIGN

Due to the significant problems of targeting recipients and the desire to have some mechanism in place to address the needs of low income households, the recommendation is to design a household tariff (referred to as a "Lifeline" Tariff) that will meet most of the objectives and at least put something in place. The proposal is to determine a lifeline amount of electricity needed by a household necessary for daily living (including such things as lighting, refrigeration, cooking, radio, television, etc.) and price that quantity at a reduced level that the average poor households can be expected to afford. An Affordability Study of the ability of various income groups to afford various amounts of electricity has not been performed; therefore, judgment will have to be used. Consumption above the lifeline amount would be priced significantly higher to fund the subsidy within the household class.

Data on household consumption is not readily available in the billing systems of some distribution companies. The data that is available, however, indicated that a fairly high percentage of households (apartments and gers) utilize 100 kWh of electricity per month or less. Since we cannot have too much usage in the lifeline portion of the household tariff (since there would be too few kWh of energy in the higher block to fund the subsidy), it is recommended that 75 kWh be used initially as the lifeline quantity. As experience is gained with the tariff arrangement over time, adjustments can be made. The point is to do something now and improve on it later. Future enhancements could include separate lifeline amounts for apartment and ger households, given the fact that ger customers generally use lower amounts of electricity due to the fact that they often cook on their coal stoves, have smaller refrigerators, and require less lighting. Also, the lifeline amount could vary with the number of people in the residence, addressing the needs of large poor families.

It is recognized that the recommended lifeline tariff proposal is not optimal. Shortcomings include the fact that it provides advantages to low use customers that are not poor. Low consumption of electricity may be due to working families with good jobs that are not home a lot and, therefore, do not need to use much electricity. Alternatively, some low-income households may need to use relatively high amounts of electricity, due to large family size for example.

A benefit of the proposed tariff is that it does encourage conservation, since energy consumption in the second block is priced so much higher. Conservation is also an objective of Mongolia's Energy Strategy. To the extent that energy is saved, scarce natural resources (specifically coal) are saved, the need for new generating capacity is reduced, and air quality improves.

A "political" benefit is also available in that politicians and government officials (as well as the ERA and Licensees) can show the public that they are doing something to address the needs of low-income households.

Section 16.3.5 of Chapter 16 provides a numerical example of the design of a lifeline tariff, including the judgmental considerations involved. The example set the tariff for the lifeline amount below the cost of service (in fact it was set at the current tariff level, while the household class in total received an increase). The kWh consumption above the lifeline was priced slightly above the cost of service to fund the “discount” on the lower consumption levels.

14. DEMAND SIDE MANAGEMENT

14.1 BASIC RATIONALE AND STRATEGIES

Demand side management is a collection of measure taken by utilities to influence (or modify) the amount or timing of customers' energy usage in order to utilize scarce resources most efficiently. Scarcity may be due to limitations of generation, transmission, or distribution facilities or to the desire to conserve fuel, other resources, or imported power. A broader definition of demand side management would encompass not only utility activities, but activities also conducted by Government agencies, such as the implementation of energy efficient building codes, appliance standards, and appliance labeling programs.

Demand side management strategies fall into five general categories as follows:

- Energy Efficiency.
- Conservation, with the general intent being to conserve scarce fuel resources.
- Load Management, to reduce the need for new facilities or to shift time of use to lower cost periods.
- Fuel Substitution
- Load Retention

Demand Side Management may be implemented to help the utility and its customers achieve various objectives including:

- Conservation
- Encouraging “Wise” (economic) use of electricity
- Reduction in Peak Load
- Defer the need for new plant and equipment
- Encourage consumption to be shifted to the time of day that power supply costs are at a relatively low level
- Avoid overload or reliability problems on the electrical system
- Reduce customer costs
- Reduce the total social (Environmental, etc.) costs of providing energy services
- Help customers increase their energy efficiency

Demand Side Management Measures can include:

- Energy efficient appliances. Subsidize or otherwise encourage the installation of efficient:
    - Light Bulbs
    - Refrigerators
    - Air conditioners

    - Electric motors

- Use of better equipment, building practices, and energy management practices in ways that reduce the total cost of energy services over time.

- Through geographically-targeted DSM, reduce or defer the need for costly distribution capacity upgrades

- Provide information to customers such as educational bulletins or product-oriented brochures

- Tariff Tools
    - Time of use tariffs
    - Interruptible tariffs
    - Voluntary Demand Curtailment
    - Proper pricing based on cost

14.2 TIME-OF-USE TARIFFS

One of the tools available to the regulator to match generation costs and customer needs is the time-of-use tariff. In general, this tariff provides the customer with the option to save on their energy cost if the economics of their operations allow them to shift usage in a manner that they match the generating costs at various times such as:

- Peak Hours
- Valley Hours
- Shoulder Hours

Shifting load from on- to off-peak periods smoothes the distribution load profiles and allows the supplier to pass the cost savings along to the customer. The ultimate time-of-use tariff is "Real Time Pricing". The customer would pay the cost of production at every hour (or appropriate increment) of the day, exactly matching the supplier's cost curve.

In Mongolia, time-of-use tariffs are currently used primarily to provide "Discounts" to large (State Owned) customers. It is a fact that the current tariff for customers receiving service at higher voltages (110 and 35 KV) is above the cost of service, however, the current time-of-use tariff is not the proper mechanism to correct the problem. Properly designed tariffs based on a Cost of Service analysis, such as the Voltage Level Cost of Service discussed in Chapter 15, preclude the need to offer "Discounts" to certain customers.

There is not currently a significant difference in the cost of power production throughout the day; therefore, the current time-of-use tariff must be modified.

14.3 INTERRUPTIBLE TARIFFS

With an Interruptible tariff, the Utility provides the Customer with a reduced tariff in exchange for the right of the utility to interrupt the customer for a specified period of time as conditions require. The reduction could be in the form of lower capacity charges, lower energy charges, or a combination of the two. Such a tariff can be applied to a range of customers. In the case of heavy industry, if electricity is a significant component of the cost of production, then the customer may take the risk of an interruption in exchange for a lower price. If the customer cost structure were such that an interruption is too costly, in the case of labor-intensive operations, then the customer would select a different tariff. The issue is often the length of each interruption and the number of interruptions per day compared to the discount received. The current situation in Mongolia is that a capacity constraint does not exist. In fact, capacity utilization of most power stations is quite low, resulting in rather high capacity costs per kWh. In the future, if generating capacity is not sufficient to meet the load, interruptible tariffs may be appropriate.

14.4 VOLUNTARY DEMAND CURTAILMENT

During periods of capacity shortage, larger customers may be given the option of curtailing their demand to make more capacity available to other customers. If the regulator wants to take advantage of this demand side management option, the major consideration is the level of compensation to the customers participating in the program. It is helpful to think of the participating customer, in this case, as a supplier to the rest of the customers. The price per kWh could be the real time marginal cost of energy or a pre-established price. Unlike an interruptible tariff, the customer has the option to determine the level and duration of the curtailment given its operating situation at the current time. Again, this is an option that ERA may decide to utilize in the future in the event of capacity shortages.

14.5 CONSERVATION

There are significant environmental and economic benefits available to the country from conserving electricity and heat. Air quality improvement is very important in Ulaanbaatar and the other large population centers of Darkhan and Erdenet. Large enterprises can become more competitive if they are able to utilize less energy in their processes. Households, many of which are at or below the poverty line, cannot afford to spend significant portions of their income on energy. Conservation of electricity and heat, and ultimately, the natural resources of the country should be given high priority by the Government of Mongolia and the ERA.

Conservation should not be implemented through a “Command and Control” system, but rather through customer education and appropriate pricing mechanisms. The Government can add value in the areas of building codes, appliance standards, and consumer education. The Distribution / Retail Supply Licensees are the entities having direct contact with Customers. Through their customer relations programs, they can provide the consumers with energy saving tips and information on how the energy bills are determined, in order that the customer can make choices on the manner in which they conserve. Encouraging customers to conserve heat by installing valves on radiators, for example, serves a dual purpose of conserving heat and providing a more comfortable environment. In Mongolia, like many other countries with central heat systems, the primary method of temperature control is to open windows to provide a comfortable temperature in the apartment. Heat distribution companies could offer lower tariffs to those customers having valves on radiators, for example.

14.6 PRICING AND COLLECTION PRACTICES

The most important Demand Side and Conservation measures have to do with properly pricing the service and collecting from customers that utilize the service. If a service is priced too low, then there is little incentive on the part of customers to conserve. A good example of this is with central heat tariffs for households, which cover only half of the cost of supply. The households living in apartments pay approximately 50% of what ger residents pay to heat their homes for the winter. Given that, on average, apartment dwellers have larger living quarters and higher household incomes than ger residents, this situation is contrary to good public policy. For that reason, it is being recommended that heat subsidies to apartments gradually be reduced.

Electricity tariffs for households are also below the cost of service, thereby sending the wrong price signals to consumers. The Cost of Service and Tariff Design chapters of this report address that issue and it is recommended that household tariffs be gradually increased to bring them closer to the cost of the service. In addition, a Lifeline Tariff is being proposed to address the joint concerns of conservation and the ability of low-income customers to be able to afford a base level of electricity.

Collection of the amounts due for energy consumption also has a significant impact on conservation. Large (primarily State Owned) entities that do not pay for their energy are wasting the country's natural resources, making energy more expensive for other consumers, and causing the value of the energy companies to deteriorate. Government officials who require the Licensees to continue to provide service to entities that do not pay are doing a disservice to the country. From an economic perspective, providing "free" electricity to commercial enterprises that are not economically viable, results in a deterioration of the overall economy. The Licensees should be allowed to disconnect customers for non-payment. If the Government decides that it is in the public interest to subsidize certain entities, then it should do so with public (Budget) funds. The Government should not use the energy sector to provide non-transparent subsidies to those entities.

Conservation objectives can also be achieved by reducing the theft of energy on the part of households. There is a feeling on the part of some households that theft of energy is not wrong. This may be due to the fact that they still view electricity as a government provided service and that it is not wrong to steal from the government. Of course, as the energy sector moves to a more commercial environment, this practice must be stopped. Households that steal electricity are actually stealing from their neighbors that pay for the service. Both the Government and the Licensees can work to change attitudes in this area through public education programs. Those persons that steal electricity should have pressure put upon them by their neighbors as well as the Licensees.

14.7 DSM IN THE CONTEXT OF THE MONGOLIAN POWER SECTOR

As previously discussed, the most important demand side and conservation measures for Mongolia at the present time have to do with properly pricing electricity and heat and insuring that customers utilizing the service pay for it.

At the present time in the Central Electricity System, there is sufficient generating capacity to meet the electricity and heat loads. Given that there is no new generating capacity currently being developed (or even planned), assuming the economy continues to grow (even at a modest rate) the system will begin to experience shortages of capacity in the coming years. Time of use tariffs will become more important and other DSM tools such as interruptible tariffs and voluntary demand curtailment may be necessary. In keeping with a more market oriented power sector, demand side management measures should be predicated on incentives for Customers and Licensees whenever possible, as opposed to mandated programs. Mandated programs should be used only when incentives are not sufficient to match supply and demand.

15. COST OF SERVICE

15.1 BASICS

Cost of Service is the process of identifying the costs of a licensee to provide service to each of the customer classes (tariff categories). The process requires knowledge of the overall business of a licensee and consideration of engineering, operational, economic, and customer relation aspects. It involves engineering and financial estimates and allocations and results in development of information that considers:

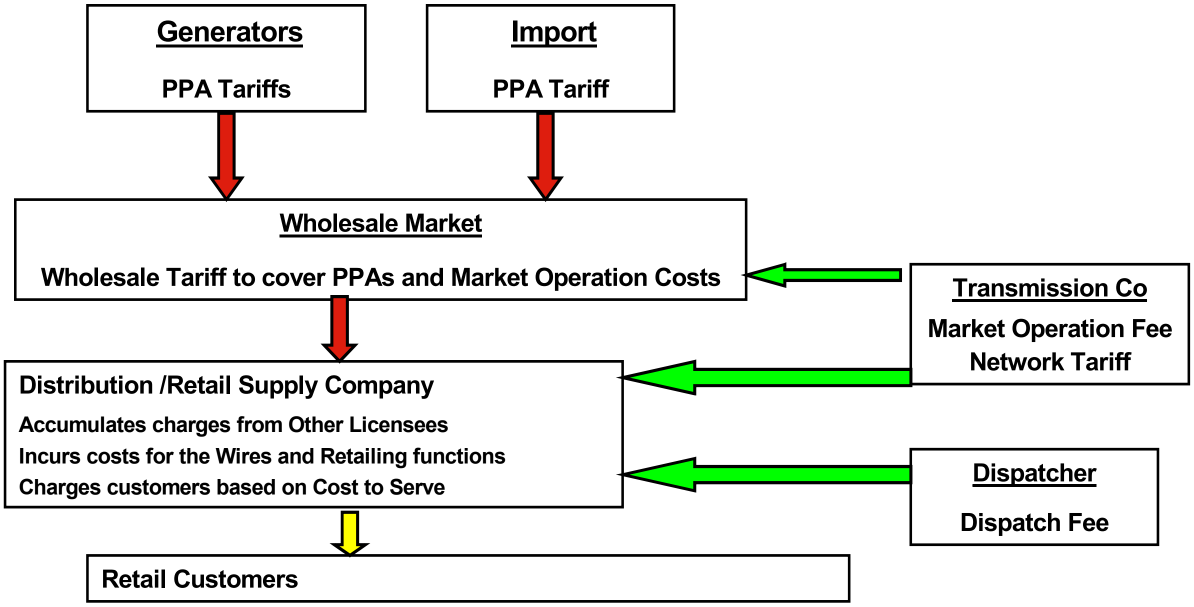
- The total revenue requirement of the licensee
- A meaningful level of detail of the ingredients of the revenue requirement in order to be able to allocate each item
- Power usage characteristics of each customer class
- Technical and commercial losses at each voltage level

A Customer Class (or Tariff Class) is a grouping of customers for which a unique tariff is to be developed. Customer groupings are generally determined based on the voltage level at which service is delivered and the usage characteristics of the class (load factor, time of use, etc.). The objective is to develop methods that allocate costs:

- In a reasonable, consistent manner
- In accordance with technical and commercial principles
- In proportion to the utilization of system resources

Retail Tariffs, in the current unbundled market structure can be thought of the sum of the costs of the various Licensees, as depicted in Exhibit 15.1.

Exhibit 15.1 Components of the Retail Tariff



The Distribution/Retail Supply Company is the focal point. It incurs costs for power from the Wholesale Market (see Chapter 6) consisting of charges from the Generation Licensees, the cost of imported power, and the Market Operation Fee. It also incurs costs for the use of the transmission network (See Chapter 7) and for the relatively small fee of the Dispatch Licensee. In addition, it has its own tariffs for distribution and retail supply (Chapter 8). The Cost of Service can be thought of as accumulating those various costs and then allocating them to the various retail customer classes.

15.2 DETERMINING CUSTOMER CLASSES

The first step is to segregate the customers into classes. The primary driver of the cost to serve customers is the voltage level at which they receive service. The voltage levels in Mongolia are as follows:

- 110 KV
- 35 KV
- 10 and 6 KV
- 400 volts and below

Within the voltage classifications, there can be different categories of customers. For example, the 400-volt class includes households, street lighting, and some small entities. Household customers could also be segregated based on type of residence (apartment and ger) if it is desired to have separate tariffs based on the cost differences to serve those customers. At the present time, there are some households with prepaid meters that have the ability to charge different prices based on time of use.

As far as the higher voltages are concerned, some entities have time of use meters and, therefore, tariffs must be designed for them.

The objective of the Cost of Service analysis is to allocate the total revenue requirement of the licensee supplying retail service to all the customer classes.

15.3 FIXED AND VARIABLE COSTS (DEMAND AND ENERGY)

Due to the nature of the energy business, a significant amount of costs are fixed. Most fixed asset related costs such as depreciation, return on investment, and maintenance of facilities are fixed, especially in the short run. There are other costs that do not vary with output such as some salary and labor related costs. Metering, billing, and collection costs also tend to be fixed based on the number of customers and are often referred to as "Customer Costs". Variable operation and maintenance costs (including fuel) are referred to as energy related.

Most fixed costs are related to the facilities installed to meet the peak load and, therefore, the cost to serve a customer class should optimally be determined based on the class contribution to peak load. Power generation planning criteria is usually based on having sufficient capacity (and reserve margin) to serve the maximum system load and, therefore, peak load is often used as the base for cost allocation. Peak loads on various parts of the transmission and distribution systems (which often occur at different times) may be used to allocate the fixed costs related to those facilities. That would follow the planning criteria for the electrical system.

If all customers had meters that recorded demand and time of use, their demands and consumption at various time periods could be determined precisely. This is practical for very large customers, but not cost effective for the majority of users. In Mongolia, as well as many other countries, customers (including large users) are not accustomed to having demand and energy tariffs. They are used to a single energy charge and that is the method that is recommended at the current time. In the future, once the tariff levels have been rationalized in such a manner that the various classes of customers are paying close to their cost of service, the metering and billing systems can be enhanced to incorporate a demand charge for those customers for which it is economic. The proposed voltage level cost of service will provide a major step forward in the near term by considering the major driver of costs, the voltage at which service is provided.

15.4 VOLTAGE LEVEL COST OF SERVICE

As previously discussed, the primary driver of the cost to serve customers is the voltage level at which they receive service. Therefore, that is the primary method to be used. In order to describe the process and make it easier for readers to comprehend the process, an example will be used. Assume that the Distribution/Retail Supply Licensee is developing a cost of service for its application for retail tariffs. The first step in performing the cost of service analysis is to analyze the energy balance of the system to determine load flows and losses at the various voltage levels. Exhibit 15.2 displays the energy balance for the Distribution Company.

Exhibit 15.2 Energy Balance

Energy Balance of the Distribution Company		
	(MWH)	**Loss Percentage**
Received from Transmission Company	500,000	
Sales to Customers at 110 KV	50,000	
Energy Delivered to 35 KV System	450,000	
Sales to Customers at 35 KV	70,000	
Losses on the 35 KV System	15,750	3.50%
Energy Delivered to 10/6 KV System	364,250	
Sales to Customers at 10/6 KV	90,000	
Losses on the 10/6 KV System	14,570	4.00%
Energy Delivered to 400 volt System	259,680	
Sales to Customers at 400 volts and belo	210,000	
Losses on the 400 volt System	49,680	19.13%
Total Sales	420,000	
Total Losses	80,000	19.05%

Since the retail tariff is a compilation of the costs of all the components, Exhibit 15.3 shows the costs of the company that must be recovered in tariffs (the revenue requirement). The Wholesale Market Price, Transmission Network Fee, and Dispatch Fee are costs assessed by other Licensees based on the tariffs approved by the ERA. Assume that the Distribution/Supply Company has determined its revenue requirement for Distribution costs and expressed that by voltage level. In addition, the retail Supply Tariff has been computed.

Exhibit 15.3 Revenue Requirement

	Tariff (Tg/kWh)	Quantity (MWH)	Total Cost (000l Tg)
Costs from Other Licensees			
Wholesale Market Price	30.00	500,000	15,000,000
Transmission Network Tariff	1.60	500,000	800,000
Dispatch Fee	0.16	500,000	80,000
Costs of Distribution/ Retail Supply Licensee			
Distribution			2,400,000
35 KV Tariff	2.70		
10/6 KV Tariff	3.80		
400 Volt Tariff	8.90		
Retail Supply	2.80		1,176,000
Total Costs			19,456,000

The task is now to allocate the total revenue requirement of 19,456 million Tg to voltage classes and determine the resulting tariffs. The results of that allocation are shown in Exhibit 15.4.

Exhibit 15.4 Cost per kWh to Serve Voltage Classes

Allocation of Unit Costs to Voltage Levels	110 KV	35 KV	10/6 KV	400 Volt
Loss % at Voltage Level		3.50%	4.00%	19.13%
Tariff At Voltage Level				
Wholesale Market Price	30.00	31.09	32.38	40.04
Transmission Network Tarifl	1.60	1.66	1.73	2.14
Dispatch Fee	0.16	0.17	0.17	0.21
Distribution Tariff		2.70	3.80	8.90
Retail Supply Tariff	2.80	2.80	2.80	2.80
Total Costs	34.56	38.41	40.88	54.09

The costs from other Licensees shown in Exhibit 15.3 are based on quantities of power received at the 110 KV level. The unit costs must be restated to determine the appropriate unit cost at the lower voltage levels, as shown in Exhibit 15.4. That is accomplished by dividing the unit tariff at the higher voltage level by: (1 – the loss percentage). For example, if the wholesale market price for power is 30 Tg/kWh at the 110 KV level, the company must charge 35 KV customers 31.09 Tg/kWh (30 / (1- .035). For power sold to a 10 KV customer the similar charge is 32.38 Tg/kWh (31.09 / (1-0.04), and so forth.

The resulting cost to serve a customer at 110 KV, therefore, is 34.56 Tg/kWh, consisting of:

- Wholesale Market Price (30.00 Tg/kWh)
- Transmission Network Tariff (1.60 Tg/kWh)
- Dispatch Fee (0.16 Tg/kWh)
- Retail Supply (2.80 Tg/kWh)

This contains all the ingredients necessary to serve that customer class. No distribution charges are assigned to those customers since they do not use the distribution system. On the other hand, customers served at 400 volts use all components of the distribution system (resulting in a distribution cost of 8.90 Tg/kWh) and experience losses at all voltage levels, resulting in higher unit costs for the other components. The 400-volt cost is, therefore, 54.09 Tg/kWh.

As a check on the accuracy of the allocations, Exhibit 15.5 was prepared to show that, when the voltage level tariffs are applied to sales at the voltage level, the company recovers its total revenue requirement of 19,456 million Tg.

Exhibit 15.5 Cost of Service by Voltage Level

Cost of Service by Voltage Level	**110 KV**	**35 KV**	**10/6 KV**	**400 Volt**	**TOTAL**
Sales (MWH)	50,000	70,000	90,000	210,000	420,000
Tariff (Tg/kWh)	34.56	38.41	40.88	54.09	
Total Cost (000Tg)	1,728,000	2,688,834	3,679,492	11,359,673	19,456,000

The Cost of Service information is then used in the next step of the process, Tariff Design.

16. TARIFF DESIGN

16.1 GENERAL TARIFF DESIGN ISSUES

Every business must develop a price structure for its product or service. Tariff Design is the process of developing a price structure for electric service by analyzing the Cost of Service information for each customer class and using that information to develop a meaningful tariff recognizing customer, licensee, and social issues, subject to various constraints such as metering and ability to pay. This process is a more creative and judgmental one than the cost of service process, although it should still be based on factual data.

The basic objective is that each class of customer should pay the cost required to serve them. If that was the only objective, the ERA could design the tariff for each customer class to recover exactly the cost of service that was determined in Chapter 15.

There are various common tariff designs that are used, depending on the customer class and metering schemes. Exhibit 16.1 lists some of the most common ones:

Exhibit 16.1 Common Tariff Designs

Description	Example
Flat rate per kWh	45 Tg per kWh
Demand and Energy Components	5,000 Tg per kW of contract demand 30 Tg per kWh consumed
Flat rate with Customer Charge	2,000 Tg per month 40 Tg per kWh Consumed
Declining Block	60 Tg for the first 100 kWh 45 Tg for 101-300 kWh 30 Tg for kWh in excess of 300
Inverted Rate	30 Tg for the first 100 kWh 45 Tg for 101-300 kWh 60 Tg for kWh in excess of 300
Time of Use	30 Tg for the 8 valley hours 45 Tg for the 8 shoulder hours 60 Tg for the 8 peak hours

The analyst responsible for designing a tariff for a particular class can use one of the methods listed above or combine two or more. For example, a demand charge and/or customer charge could be utilized in conjunction with a time of use tariff. The important thing is to design the tariff in a manner that, when it is applied to customer demand and usage patterns over the period of time it is in effect, it recovers the cost of service of the customer class.

A flat rate per kWh is a very simple design to handle in billing systems and for customers to understand. The declining block rate can be utilized to recover some of the fixed costs (demand or customer costs) in the first block and only energy charges in the final block. That mechanism, although it may be cost based, results in a high tariff for low use customers, many of who may be poor. The inverted rate is becoming more common, especially with residential classes, since it encourages conservation by penalizing customers for utilizing energy in the upper block. Conservation and environmental considerations can be factored into tariffs in this manner. If lower levels of consumption are desired to conserve scarce resources or reduce emissions from fossil power generation facilities, then tariffs may be structured to encourage reduced usage. The resulting tariff may deviate from strict cost based criteria to meet such objectives. This structure also provides a way to implement a lifeline tariff if the first block includes the number of kWh determined to be the lifeline quantity and if the rate per kWh is set at a low enough value. If applied to a broad customer class, however, it may not target the appropriate customers in the most effective way. Chapter 13 discusses the lifeline tariff in more detail.

Time of use tariffs allow the customer to be aware of the fact that the suppliers costs may vary throughout the day and, therefore, give the customer the opportunity to adjust their usage patterns (based on the economics of their situation) to take advantage of that fact. This creates a win-win situation for both parties. The limiting factor here is the cost of metering.

A tariff with demand and energy components recognizes that fixed costs must be recovered regardless of energy consumed. In developed countries, it is the most common tariff design for large customers, while for small users; the cost of metering is prohibitive at the present time. A flat customer charge per month is often used as a proxy for a demand charge, with the flat charge designed to recover some demand related costs as well as customer costs such as metering, billing, and collection.

The tariff structure in Mongolia is currently quite simple, with most tariffs only including an energy charge. The tariffs being recommended (although more extensive than the current schedules) do not include demand components due to the lack of metering capacity and cost involved. As the ERA makes enhancements to the tariff process in the future, demand and energy tariffs will undoubtedly be introduced. The reader will note that the wholesale price of energy is charged based on a flat rate per kWh. That mechanism could change in future years and demand and energy charges could be used.

In addition to the standard or base tariff structure, there may be additional charges to customers for additional services provided by the supplier for special use equipment, redundant service connections for security, or reactive power. Surcharges are also common for tariff adjustment mechanisms to cover fluctuations in various costs or unexpected changes in price levels or exchange rates.

Again, the job of the tariff designer is to develop a tariff for each class that recovers the cost of service for that class. Social considerations such as ability to pay, in the case of households or certain businesses, often enter into the design of tariffs. There is no free subsidy, however. Either the government or other consumers must pay. Those tariffs designed to recover less than the full cost of service will have to be offset by other tariffs recovering more than the cost of service. A Cost of Service Index is the measure used to gauge the deviation from full cost of service. An index value of 1 indicates the customer class is paying the full cost of service. Values less than 1 indicate under recovery and those over 1 indicate over recovery of the cost of service. The ERA, customers, and other interested parties should be made aware of the index value for each class to make the tariff design process a transparent one and to be able to quantify the cross subsidies.

Appendix C (discussed in Chapter 18) contains the requirements for applicants when requesting a tariff adjustment. The requirements call for applicants to include a proposed tariff design for each tariff class with their tariff application.

16.2 DETERMINING OVERALL TARIFF LEVELS

Since we are using voltage level as the primary determinant of costs, the first step in tariff design is to analyze the current tariff levels by voltage level compared to the cost of service. Using the sample data from Chapter 15, a comparison of revenue for the forecast period at current tariffs compared to the cost of service can be made as shown in Exhibit 16.2.

Exhibit 16.2 Current Tariffs vs. Cost to Serve

Customer Class	Sales (MWH)	Current Tariff (Tg/kWh)	Current Revenue (000 Tg)	Cost of Service (Tg/kWh)	Cost of Service (000 Tg)	Over/(Under) Recovery (000 Tg)	COS Index
110 KV	50,000	44.00	2,200,000	34.56	1,728,000	472,000	1.27
35 KV	70,000	45.00	3,150,000	38.41	2,688,834	461,166	1.17
10/6 KV	90,000	46.00	4,140,000	40.88	3,679,492	460,508	1.13
400 volt	210,000	46.00	9,660,000	54.09	11,359,673	(1,699,673)	0.85
Totals	420,000		19,150,000		19,456,000	(306,000)	0.98

Current tariffs are projected to recover 98% of the cost of service in total. The “Over/Under Recovery” column quantifies the cross subsidies existing between the classes. The Cost of Service (COS) Index for each class shows, for example, that the 110 KV customers are paying 27% more than the cost to serve them while the 400-volt class tariff is only 85% of the cost to serve it.

The next step is to restructure the overall tariffs by voltage to:

1. Recover an additional 306 million Tg, and
2. Gradually bring the individual tariffs closer to a COS Index of 1.0

The restructuring process is a judgmental one based on how rapidly the tariff designer wants to bring the COS Index closer to 1. THERE IS NOT A “CORRECT” ANSWER TO THIS PORTION OF THE ANALYSIS. Exhibit 16.3 displays one of many possible ways to gradually adjust tariffs.

Exhibit 16.3 Tariff Restructuring Example

Class	Sales (MWH)	Current Tariff (Tg/kWh)	Current Revenue (000 Tg)	Cost of Service (000 Tg)	Tariff Change (%)	New Tariff (Tg/kWh)	New Revenue (000 Tg)	Recovery (+ / -) (000 Tg)	COS Index
110 KV	50,000	44.00	2,200,000	1,728,000	-5.0%	41.80	2,090,000	362,000	1.21
35 KV	70,000	45.00	3,150,000	2,688,834	-3.0%	43.65	3,055,500	366,666	1.14
10/6 KV	90,000	46.00	4,140,000	3,679,492	0.0%	46.00	4,140,000	460,508	1.13
400 volt	210,000	46.00	9,660,000	11,359,673	**5.3%**	**48.43**	10,170,500	(1,189,173)	0.90
Totals	420,000		19,150,000	19,456,000			19,456,000	0	1.00

The rationale for the proposed tariffs is as follows:

- The 110 KV class is currently paying 27% above cost. This class is the one that, as the country moves to a more competitive market environment, has the most options. Currently, it also has the option of self-generating, in this case leaving the remaining customers on the system with all the related fixed costs. The ERA should have a target of moving the tariff to a COS Index of 1 over a period of, say 5 years. Since these customers represent the heavy industry of the country, the GOM should be interested in having the tariff as competitive as possible. For those reasons, a 5% reduction was assumed, bringing the COS Index down to 1.21.
- The 35 KV class is currently paying 17% above cost. This class is similar to the 110 KV class in that it has options and consists of some very large industry, and should have relatively competitive tariffs. The ERA should have a target of moving the tariff to a COS Index of 1.05 over a period of say 5 years, still providing a modest subsidy to households. For those reasons, a 3% reduction was assumed, bringing the COS Index down to 1.14.
- The 10 and 6 KV class is currently paying 13% above cost. This class consists of smaller industrial enterprises, and other commercial entities. Unlike the 110 and 35 KV classes, these customers have fewer options and are generally the ones that provide a subsidy to households. The ERA should have a target of moving the tariff to a COS Index of 1.10 over a period of say 5 years, still providing a modest subsidy to households. For the purpose of this example, no tariff change was assumed. Remember that we want to move tariffs gradually and in order to still provide a subsidy to households, the Distribution/Supply Licensee has to get the money from other tariff classes.
- The 400-volt tariff was used as the balancing item. After the above changes, the company must collect the total revenue requirement and in order to do that a 400-volt tariff averaging 48.43 Tg/kWh is required, resulting in a 5.3% tariff increase for the class and bringing the COS Index to 90%.

Now that the overall cost recovery targets have been determined, the individual tariffs by sub-class must be designed.

16.3 DESIGNING INDIVIDUAL TARIFFS

16.3.1 Supplemental Information Needed

Time-of-use tariffs are currently available to certain customers at all voltage levels. In the past, such tariffs have been used partially to provide "Discounts" to certain customers since decision makers recognized that some tariffs were too high. Now that tariffs are to be based more closely on costs, arbitrary adjustments are not necessary. A review of the marginal cost of power generation throughout the day indicates that there is not a significant difference from hour to hour. This is partially due to the fact that the CES has a fixed generation base that is dispatched to a great extent based on heat load.

Certain customers (especially large ones), however, are accustomed to such tariffs and this may result in some flattening of the load curve, resulting in less need for generation capacity. Transmission and distribution capacity is also better utilized, although in general, there are no constraints on those systems. It is recommended that the time-of-use tariff concept be continued for those customers, however, it should be based more heavily on cost.

The current time of use tariff for entities (regardless of voltage) is:

Evening (On Peak)	94 Tg/kWh
Day (Shoulder hours)	47 Tg/kWh
Night (Off Peak)	17.6 Tg/kWh

As a target, it is recommended that the ERA set the off peak tariff at least equal to:

- The Energy Charge (variable cost) component of the Wholesale Market Tariff
- 50% of the Fixed Cost component of the Wholesale Market Tariff
- The Transmission Network Tariff
- The Dispatch Fee
- The Distribution Tariff, depending on voltage
- The Retail Supply Tariff

The tariff designer must, therefore, determine the energy component of the Wholesale Market Tariff. Assume that the current Wholesale Market Tariff is 30 Tg/kWh, consisting of an Energy Component of 10 Tg/kWh and a Capacity Component of 20 Tg/kWh at the 110 KV level. Off-Peak use should therefore be priced at 20 Tg/kWh. Using the loss percentages at the various voltage levels (from Exhibit 15.2), the resulting wholesale cost component would be as follows:

110 KV	20.00 Tg/kWh
35 KV	20.73 Tg/kWh
10/6 KV	21.59 Tg/kWh
400 Volt	26.70 Tg/kWh

The other cost components are already available from the Cost of Service information in Exhibit 15.4.

For every detailed tariff schedule being proposed, the Licensee must submit an estimate of the sales and any other usage characteristics of the customers. For example, at the 110 KV level, if it is desired to have a Basic tariff and a Time-of-Use tariff, sales estimates must be provided for the estimated sales at the Standard tariff and for estimated sales by time of use (on-peak, off-peak, and shoulder).

16.3.2 Tariffs for Customers Served at 110 KV

At the 110 KV level, there are two Tariff Schedules proposed, a Standard Tariff and a Time-of-Use Tariff. Exhibit 16.4 contains some the information needed to design the tariffs.

Exhibit 16.4 110 KV Sales and Cost Data

Revenue to be recovered (000 Tg)	2,090,000
Sales (Mwh)	
Basic Tariff	30,000
Time of Use:	
Evening (On Peak))	4,000
Day (Shoulder)	7,000
Night (Off Peak)	9,000
Total Sales	50,000
Average Tariff (Tg/kWh)	41.80
Calculation of Minimum Off Peak Tariff:	
Wholesale Price	20.00
Transmission	1.60
Dispatch	0.16
Distribution	-
Retail Supply	2.80
TOTAL	24.56

The design of the individual tariffs is then performed. Assume the result is as shown in Exhibit 16.5.

Exhibit 16.5 110 KV Tariff Design

	110 KV Tariffs	**Sales (MWH)**	**Tariff (Tg/kWh)**	**Revenue (000 Tg)**
Tariff Schedule				
A	Basic Tariff	30,000	41.80	1,254,000
B	Time of Use:			
	Evening (On Peak))	4,000	80.59	322,360
	Day (Shoulder)	7,000	41.80	292,600
	Night (Off Peak)	9,000	24.56	221,040
	TOTALS	50,000		2,090,000

The Basic Tariff was set at the average proposed tariff for the 110 KV class (41.80 Tg/kWh) as determined in Exhibit 16.3. The Time-of-Use Tariff was designed to have the Day, or shoulder tariff at the average, the Off-Peak Tariff equal to the minimum price of 24.56 (from Exhibit 16.4) and the On-Peak tariff was designed by having the revenue equal the remaining amount needed to recover the total revenue requirement with the resulting tariff required of 80.59 T/kWh. The proposed Time-of-Use tariff has a more narrow range (24.56 to 80.59) than the current tariff (17.6 to 94), keeping with our principle of moving tariffs gradually.

16.3.3 Tariffs for Customers Served at 35 KV

At the 35 KV level, there are two Tariff Schedules proposed, a Standard Tariff and a Time-of-Use Tariff. Exhibit 16.6 contains some the information needed to design the tariffs.

Exhibit 16.6 35 KV Sales and Cost Data

Revenue to be recovered (000 Tg)		3,055,500
Sales (Mwh)		
Basic Tariff		40,000
Time of Use:		
Evening (On Peak))		5,000
Day (Shoulder)		10,000
Night (Off Peak)		15,000
	Total Sales	70,000
Average Tariff (Tg/kWh)		43.65
Calculation of Minimum Off Peak Tariff:		
Wholesale Price		20.73
Transmission		1.66
Dispatch		0.17
Distribution		2.70
Retail Supply		2.80
	TOTAL	28.06

The design of the individual tariffs is then performed. Assume the result is as shown in Exhibit 16.7.

Exhibit 16.7 35 KV Tariff Design

	35 KV Tariffs	**Sales (MWH)**	**Tariff (Tg/kWh)**	**Revenue (000 Tg)**
Tariff Schedule				
A	Basic Tariff	40,000	43.65	1,746,000
B	Time of Use:			
	Evening (On Peak)	5,000	90.42	452,100
	Day (Shoulder)	10,000	43.65	436,500
	Night (Off Peak)	15,000	28.06	420,900
	TOTALS	70,000		3,055,500

The Basic Tariff was set at the average proposed tariff for the 35 KV class (43.65 Tg/kWh) as determined in Exhibit 16.3. The Time-of-Use Tariff was designed to have the Day, or shoulder tariff at the average, the Off-Peak Tariff equal to the minimum price of 28.06 (from Exhibit 16.6) and the On-Peak tariff was designed by having the revenue equal the remaining amount needed to recover the total revenue requirement with the resulting tariff required of 90.42

T/kWh. The proposed Time-of-Use tariff has a more narrow range (28.06 to 90.42) than the current tariff (17.6 to 94), keeping with our principle of moving tariffs gradually.

16.3.4 Tariffs for Customers Served at 10 and 6 KV

At the 10/6 KV level, there are again two Tariff Schedules proposed, a Standard Tariff and a Time-of-Use Tariff. Exhibit 16.8 contains some the information needed to design the tariffs.

Exhibit 16.8 10/6 KV Sales and Cost Data

Revenue to be recovered (000 Tg)	4,140,000
Sales (Mwh)	
Basic Tariff	70,000
Time of Use:	
Evening (On Peak))	3,000
Day (Shoulder)	7,000
Night (Off Peak)	10,000
Total Sales	90,000
Average Tariff (Tg/kWh)	46.00
Calculation of Minimum Off Peak Tariff:	
Wholesale Price	21.59
Transmission	1.73
Dispatch	0.17
Distribution	3.80
Retail Supply	2.80
TOTAL	30.09

The design of the individual tariffs is then performed. Assume the result is as shown in Exhibit 16.9.

Exhibit 16.9 10/6 KV Tariff Design

	10/6 KV Tariffs	Sales (MWH)	Tariff (Tg/kWh)	Revenue (000 Tg)
Tariff Schedule				
A	Basic Tariff	70,000	46.00	3,220,000
B	Time of Use:			
	Evening (On Peak)	3,000	99.03	297,100
	Day (Shoulder)	7,000	46.00	322,000
	Night (Off Peak)	10,000	30.09	300,900
	TOTALS	90,000		4,140,000

The Basic Tariff was set at the average proposed tariff for the 10/6 KV class (46.00 Tg/kWh) as determined in Exhibit 16.3. The Time-of-Use Tariff was designed to have the Day, or shoulder tariff at the average, the Off-Peak Tariff equal to the minimum price of 30.09 (from Exhibit 16.8) and the On-Peak tariff was designed by having the revenue equal the remaining amount needed to recover the total revenue requirement with the resulting tariff required of 99.03 T/kWh. The proposed Time-of-Use tariff has a slightly narrower range (30.09 to 99.03) than the current tariff (17.6 to 94), however, the On-Peak tariff is slightly higher than the current one.

16.3.5 Tariffs for Customers Served at 400 Volts

The tariffs for the higher voltages (6 – 110 KV) were designed in a rather straightforward manner, as shown in the prior sections. At the 400-volt level, a wider range of tariffs is proposed and much more judgment (and a fair amount of creativity) is needed. Both Entities and Households receive service at this voltage. As far as Entities are concerned, there is currently a Basic Tariff, a specific Street Light Tariff, and a Time-of-Use Tariff. It is assumed that those tariff classes will be continued. For Households, the Basic Tariff is proposed to be a Lifeline Tariff (See Chapter 13), with the "lifeline" usage estimated to be 75 kWh per month. Some households have Time-of-Use meters (actually, prepaid meters with time-of-use capability) and it is assumed that that tariff will be continued. Sales estimates and cost data are shown in Exhibit 16.10.

The basic task is to design tariffs for the class to recover the desired revenue (10.17 billion Tg) from the customers.

Exhibit 16.10 400-Volt Sales and Cost Data

Revenue to be recovered (000 Tg)	10,170,500
Sales (Mwh)	
Entities	
Basic Tariff	25,000
Street Light::	
On-Peak	5,000
Off-Peak	10,000
Time of Use:	
Evening (On Peak))	2,000
Day (Shoulder)	5,000
Night (Off Peak)	8,000
TOTAL ENTITIES	55,000
Households	
Basic - Lifeline Tariff	
0-75 kWh / Month	100,000
Over 75 kWh / Month	50,000
Time of Use	
Day	2,000
Evening/Night	3,000
TOTAL HOUSEHOLDS	155,000
Total 400 Volt Sales	210,000
Average Tariff (Tg/kWh)	48.43
Calculation of Minimum Off Peak Tariff:	
Wholesale Price	26.70
Transmission	2.14
Dispatch	0.21
Distribution	8.90
Retail Supply	2.80
TOTAL	40.75

Entity tariffs will be discussed first, with the results shown in Exhibit 16.11.

Exhibit 16.11 Tariff Design for Entities Served at 400 Volts & Below

400 Volt Tariffs - Entities		**Sales (MWH)**	**Tariff (Tg/kWh)**	**Revenue (000 Tg)**
Tariff Schedule				
A	Basic Tariff	25,000	50.00	1,250,000
B	Street Light			
	On-Peak	5,000	45.00	225,000
	Off-Peak	10,000	29.05	290,500
C	Time of Use:			
	Evening (On Peak)	2,000	80.00	160,000
	Day (Shoulder)	5,000	50.00	250,000
	Night (Off Peak)	8,000	40.00	320,000
	TOTALS	55,000		2,495,500

The Basic Tariff was set at 50 Tg/kWh, slightly above the average target for this voltage class of 48.43 but below the full cost of service of 54 Tg. As compared to Households, it is assumed that entities served at this voltage (primarily small establishments) have greater ability to pay and less sensitivity to price than households. The Street Light Tariff is currently 47 Tg for on-peak and 4.7 Tg for off-peak. The off-peak tariff is currently far below the cost of fuel used to generate the power and must be significantly increased to 29 Tg, covering fuel cost and making some contribution to fixed costs, but still below the target of 40 Tg. The on-peak price of 45 Tg recognizes that commercial losses for this customer are lower than average. The Time-of-Use Tariff was designed using a Day rate close to the average target price for the class, a Night rate close to the minimum cost, and the Evening tariff was assumed to be twice the minimum.

Exhibit 16.12 Tariff Design for Households

400 Volt Tariffs - Households		**Sales (MWH)**	**Tariff (Tg/kWh)**	**Revenue (000 Tg)**
Tariff Schedule				
A	Lifeline Tariff			
	0-75 kWh / Month	100,000	46.00	4,600,000
	Over 75 kWh / Month	50,000	58.00	2,900,000
C	Time of Use:			
	Day	2,000	50.00	100,000
	Evening/Night	3,000	25.00	75,000
	TOTALS	155,000		7,675,000

The Lifeline Tariff, more fully discussed in Chapter 13, assumes a lifeline quantity of 75 kWh per month priced at the current tariff. This gives politicians and government officials the opportunity to communicate to customers that, although household tariffs in total must increase, customers can still acquire a base level of electricity for the current price. Usage above the lifeline amount is assumed to be priced at 58 Tg, above the total cost of service for the class of 54 Tg, but necessary to offset the lower lifeline price and still recover the total cost of service for the 400-volt class. Remember that all households (regardless of income) are eligible for this tariff and, therefore, their average tariff is lower. Households consuming over 225 kWh per month would pay an average tariff above the cost to serve, however. This does provide incentive to conserve.

The Time-of-Use Tariff currently provided to households having prepaid meters is 47 Tg for Day use and 10.4 Tg for Evening and Night. Obviously, the 10.4 Tg is currently below even the cost of fuel used to generate the power and must be significantly increased to 25 Tg, covering fuel cost and making some contribution to fixed costs, but still far below the target of 40 Tg. It was felt that this tariff must be changed somewhat gradually to prevent customer backlash.

The tariff design for the 400-volt class is, therefore, complete with the total revenue requirement of 10.17 billion Tg recovered (2.495 billion from Entities and 7.675 billion Tg from Households).

17. PERIODIC REPORTING BY LICENSEES TO ERA

17.1 REGULATORY OVERSIGHT AND THE NEED FOR REPORTING

The Energy Regulatory Authority (ERA) has important responsibilities with respect to the oversight and monitoring of licensed activities, in addition to the review and approval of tariffs. To effectively carry out its role in this area, technical, economic, and financial information is needed. In some cases, this information is at a low level of detail. In a regulated environment, licensed entities are responsible for managing their operations in an efficient manner from both a technical and economic perspective. It is the regulator's responsibility to monitor the performance and results of the licensees. The regulator should not wait until a tariff application is filed to review licensee results. Periodic review reduces the number of "Surprises" that can occur during tariff proceedings.

The purpose of this chapter is to review the reporting structure that licensees will use to periodically report operational and financial information to ERA to carry out its oversight role. Objectives of the recommendation are to:

- Insure that information is provided to ERA in an accurate, timely, and consistent manner in a format that is useful.
- Prevent an unnecessary burden being placed on the entities that will have to implement it.
- Attempt to achieve transparency of operating and financial information.
- Have the periodic reports facilitate an ongoing dialog between the ERA, its Staff, and the reporting Licensee.

Transparency is very important in a regulated industry. The regulator, customers, and other interested parties must have access to information in order to assess the financial condition and operating performance of licensees. In the case of the Wholesale Market for electricity in the Central Electricity System, all market participants must be aware of the costs being charged to the Wholesale Market account and the methodology for determining the Wholesale Market price charged. At the present time, the Transmission Licensee is also responsible for overseeing the Market Banker activities, currently performed by a commercial bank. Transparency in this process is vital to all other Licensees, since their cash flows depend on it.

The Staff of the ERA has done a very good job in developing the majority of the reporting formats contained herein. The Advisor developed the reporting formats related to the Wholesale Market activity and the Cash Settlement Process.

To make the information useful to ERA and other interested parties, Licensees are required to submit the information in electronic form, in addition to filing a hard copy report.

Reporting requirements and formats are specified in this report, however, the process should not be a static one. Information requirements change over time and emphasis shifts to various critical areas over time. It is recommended that the ERA review the reporting requirements on a bi-annual basis, considering its information needs, the reporting capability of licensees, and other input from licensees.

Concerns have been expressed by Licensees that they are being required to spend a significant amount of time preparing reports for various governmental agencies, including Ministry of Finance and Economy, Ministry of Infrastructure, the Fuel and Energy Authority, State Property Committee, the Tax Authority, and ERA. Commercial enterprises often are required to provide information to multiple government agencies for various purposes. Agencies concerned with tax and corporate governance issues have unique information needs that must be met. The ERA is concerned with regulating an industry and, therefore, has a different focus. There is a concern, however, that certain operational and financial data being reported to the ERA is also required (in slightly different formats) by the Fuel and Energy Authority and Ministry of Infrastructure. Since the ERA is responsible for energy sector regulation, according to the Energy Law, it should be the primary governmental body responsible for such data. Since the information given to the ERA is "Public Information"[2], it is recommended that the FEA and MOI be given access to the information collected from Licensees. That will preclude Licensees from having to do burdensome excess reporting.

17.2 REPORTING REQUIREMENTS

The reporting forms are contained in Appendix A. Exhibit 17.1 summarizes those reporting requirements by giving a synopsis of each the required forms.

[2] At the present time, the author is not aware of any information being provided to ERA that is confidential. As the sector moves closer to a competitive environment and certain information is considered confidential, the ERA may have to protect certain data from unauthorized use.

Exhibit 17.1 Periodic Reporting Requirements of Licensees

Form #	Description	Licensee Category
1	Operational and Technical Indices (Quarterly)	Generation
2	Import and Export Transaction Detail (Quarterly	Import
3	Operational and Technical Indices (Quarterly)	Transmission
4	Operational and Technical Indices (Quarterly)	Heat Distribution and Supply
5	Operational and Technical Indices (Quarterly)	Electric Distribution and Supply
6	Information on Electric Customers (Quarterly)	Electric Distribution and Supply
7	Power Station Output, Sales, Billing and Collection (Monthly)	Generation
8	Purchases, Sales, Billing, and Collection (Monthly)	Electric Distribution and Supply
9	Purchases, Sales, Billing, and Collection (Monthly)	Heat Distribution and Supply
10	Accounts Receivable Information (Monthly)	All
11	Current Liability Information (Monthly)	All
12	Heat Sales Detail (Quarterly)	Heat Distribution and Supply
13	Wholesale Market Transactions in CES (Monthly)	Transmission
14	Cash Settlement and Collection Results (Monthly)	Transmission

The reader is encouraged to review Appendix A for the detailed reporting elements.

18. TARIFF APPLICATION PROCEDURES

18.1 THE NEED FOR CONSISTENCY IN TARIFF APPLICATIONS

In a regulatory environment, it is the responsibility of the applicant to fully document its request for a change in tariffs. It is the regulator's responsibility to analyze and review that request, along with the supporting documentation, and to issue a decision. To carry out this responsibility, the ERA and its Staff must have sufficient information in a format that is useful for regulatory purposes. Very often, the manner in which data is categorized for internal use (management accounting) or for external use in reporting to owners, creditors, or the general public (financial accounting) is not the same as regulators need.

Other major considerations in the development of the Tariff Application Procedures are transparency, clarity, and uniformity. A tariff application can be a highly technical document containing significant technical and financial information. Having that information presented in a clear and well-organized manner can help improve the overall process. Although the ERA and its staff have the technical expertise to understand and interpret the material, other parties involved in the tariff process may not have the same background and expertise. A clear and well-organized tariff application will benefit those parties.

In a tariff proceeding, the Licensee has the burden of proof and, therefore, should take steps to present its position clearly in order that the ERA and other parties understand the position and the information being presented. In that manner, the ERA Staff and other parties can present information, methodologies, and other points of view that can be compared to the Licensee's.

18.2 TARIFF APPLICATION REQUIREMENTS

The ERA has conducted two major tariff application processes to date. The author has reviewed the materials supplied by Licensees and the utilization of those materials by the staff of the ERA. Given that the sector has been restructured with many new companies and a new interim tariff process utilized, the materials supplied by Licensees have been of quite good quality. It is apparent that much effort was put into the application submissions. There is a need for greater consistency among Licensees, however. The Long-Term Tariff Methodology contained in this report requires that information be supplied in different manner and that Licensees present the material in a manner that will allow the various tariffs to be computed.

Tariff Application Requirements have been developed for two of the major categories of licensees, Generation and Distribution/Retail Supply. Those requirements are contained in Appendix C. Significant elements include:

- General guidelines to remind Licensees of the importance of:
  - Presenting their position clearly and supplying the relevant support materials, assumptions, methodologies, etc.
  - Furnishing the source of information and units of measure used in schedules
  - Providing both electronic and hard copy
- Schedules containing the information to calculate the Revenue Requirement and allocate that Revenue Requirement to the appropriate lines of business and tariff classes

- A schedule of the proposed Rate of Return (Cost of Capital), including the proposed Return on Equity
- Proposed Tariffs for each customer class
- Technical and operating parameters to allow the ERA to assess and evaluate the performance of the Licensee
- A statement of actions being taken by the Licensee to improve operations, reduce costs, and improve service levels.

Licensees are to present the required information in both hard copy and electronic format. In addition to the required data elements, Licensees may also be furnishing supplemental schedules (often referred to as working papers) and other supporting documentation. That information should also be in electronic form, when available. Those documents being provided that are not available in electronic format should be noted as such. Licensees are also reminded to specify the source of information (accounting records, billing system, government report, etc.) and to include the unit of measure (KW, kWh, Tg, etc.) for numerical values.

The Staff of the ERA is encouraged to develop similar requirements for the other License categories, including Electricity Transmission and Heat Networks. The tariff process is continually evolving. For that reason, these recommended filing requirements should be reviewed on a periodic basis. ERA should encourage Licensees and other interested parties to propose enhancements to the requirements. Over time, certain information may no longer be needed, new information may be needed, and information technology will evolve. The ERA is encouraged to make revisions as necessary.

18.3 TARIFF APPLICATION REVIEW AND APPROVAL PROCESS

It is very important that the tariff process be as transparent as possible and insure fairness to Consumers and Licensees. Also important, is the communication to the public of the reasons for the tariff adjustments. This became apparent in July 2002 when there was significant public outcry against the tariffs approved by the ERA. Politicians then intervened and put significant pressure on the ERA to reduce the tariff increases. The author believes that if the public and government officials had been provided with a formal tariff order specifying the issues and reasons for the increase, the pressure would have been lessened. For example, a significant portion of the increase in tariffs in the Central Electricity System was due to the fact that the Government of Mongolia increased the price of coal, a significant element of cost for Licensees. That fact should have been made very clear to the public and politicians.

A Tariff Review and Approval Process is, therefore, being recommended. The primary steps are as follows:

1. Licensee Submission of Tariff Application
2. Review of Licensee Proposal by the ERA Staff
3. Submission of ERA Staff Recommendation
4. Public Hearing on Tariff Application
5. Issue Tariff Order
6. Issue Press Release

Each of those steps is discussed in the following Sections.

18.3.1 Licensee Submission of Tariff Application

The Licensee should develop its tariff application in accordance with the Tariff Application Requirements discussed in Section 18.2. That tariff application is then presented to the ERA and should also be made available to other interested parties (consumer groups, customers, etc.).

18.3.2 Review of Licensee Proposal by the ERA Staff

The next step is for the staff of the ERA to review the submitted materials for completeness. If required materials are missing, the staff should notify the licensees immediately so the licensees have the opportunity to submit the necessary materials.

The staff should then perform an in-depth review of the materials. In their review of the proposals, the staff should utilize various analytical methods and draw on their expertise in the energy sector and their technical and economic backgrounds. Emphasis should be placed on the major elements of cost.

They should also review information from other sources so they can do an independent assessment of selected information. For example, the Dispatch Center has information on historical output of the generating stations and delivery of electricity and heat to the EDOs and HDOs. Also, the Licensees provide information to the ERA on a periodic basis (See Chapter 17 and Appendix A) that is useful to refer to when reviewing the materials. Loan interest expense is a significant cost for several licensees; therefore, a review of loan documentation and the on-lending agreements between the Government of Mongolia and the licensees would provide assurance that the amounts are correct. Fuel prices can be reviewed since coal prices are published. Analysis of the quantities, unit prices, and fuel rates will produce useful information. In the course of their review, if the staff feels that they need additional information or explanation of specific components, they should feel free to request the necessary information from individual licensees. An open exchange of information and good professional working relationships between the ERA Staff and Licensees can make the tariff process more effective and efficient.

18.3.3 Submission of ERA Staff Recommendation

When the ERA Staff completes its review of the tariff proposal of a licensee, it should summarize its findings for presentation to the Board of Regulators. The Licensee and any other interested parties should also receive a copy. The general format shown in Exhibit 18.1 is suggested as a summary for the staff presentation to the Board. Such a summary will allow the Board and the Licensee to have a concise view of the differences between the Staff recommendation and Licensee application. Of course, the Staff should document the reasons for the adjustments and present any other material they feel is necessary.

Exhibit 18.1 ERA Staff Summary of Findings

Category	Licensee Submission	Staff Adjustments	Staff Recommendation
I. Operation and Maintenance			
Adjustments:			
a)			
b)			
c)			
d)			
Total Operation & Maintenance			
II. Depreciation			
Adjustments:			
e)			
f)			
Total Depreciation			
III. Taxes			
Adjustments:			
g)			
Total Taxes			
IV. Return on Investment:			
Investment (Rate Base)			
Explanation of Adjustments:			
h)			
i)			
j)			
Total Rate Base			
Cost of Capital			
Cost rate on Long-Term Debt			
Cost rate on Short-Term Debt			
Return on Equity			
Adjustments:			
k)			
l)			
Rate of Return (%)			
Total Return on Investment			
Total Revenue Requirement			
Sales or Output Quantities			
Tariffs			

In addition to the summary information presented in the table, the Staff should present any other information it feels would be useful to the Board of Regulators in deciding on the final amount for the tariff. Useful information may include licensee efforts to reduce cost, improve service, reduce losses, improve collections, etc. Recommended areas for improvement should also be noted, where appropriate.

18.3.4 Public Hearing on Tariff Application

The Board of Regulators should hold a public hearing at which the ERA Staff presents its findings, the Licensee responds to those findings, and other interested parties (consumer groups, individual customers, etc.) are allowed to provide input. Board Members may ask the staff or Licensee for additional information or for more in-depth analysis.

18.3.5 Issuance of a Tariff Order

The Energy Law specifies the manner in which the Board must conduct itself on tariff and other matters. Article 9.2 states:

> *"The Regulatory Authority shall discuss issues to be resolved at the Regulatory Board Meeting. The Board Meeting shall issue its decisions in a form of a resolution. Licensees and consumers must comply with the resolution."*

Once the Board is satisfied it has sufficient information on which to base a decision, it should prepare its tariff order in the form of a resolution, issue it in writing, and hold a Board meeting. The tariff order should clearly spell out the tariff request of the licensee, the Board's decision on each major element of the request, and the resulting revenue requirement being approved for inclusion in the tariff. A table similar to the one shown in Exhibit 18.1 should be included in the order, documenting the differences between the Licensee application and the final tariff order. Each significant adjustment made by the Board should be discussed. The Board should also take advantage of this opportunity to discuss any other issues pertaining to the tariff, operational performance, recommended areas for improvement, customer relations, etc. This will give the licensee an insight into expectations of the Board. A major objective is to make the tariff process as transparent as possible. A well-written order facilitates that objective. Copies of tariff orders issued by regulatory bodies in other countries are being made available to the Board to give them background information. The ERA can also take advantage of the Regulatory Partnership with the Minnesota Public Service Commission, meetings with the US Federal Energy Regulatory Commission, and its membership in the Energy Regional Regulators Association to obtain information on orders issued by other regulators.

18.3.6 Issue a Press Release

The Energy Law specifies the manner in which the Board must conduct itself on tariff and other matters. Article 27.5 states:

> *"The Regulatory Authority shall notify consumers or publish in mass media information about changes in energy tariffs no later than 15 days prior to the date when these changes become effective."*

A “Press Release” should then be prepared by the Board and issued in order that the 15-day notification requirement is met. The Board should take the opportunity to explain to the public, not only the amount of the new tariffs, but also the reasons for the changes and any other information necessary for the public to understand the decision.

APPENDIX A: PERIODIC REPORTING OF LICENSEES TO THE ENERGY REGULATORY AUTHORITY

Form #	Description
1	Operational and Technical Indices (Quarterly)
2	Import and Export Transaction Detail (Quarterly
3	Operational and Technical Indices (Quarterly)
4	Operational and Technical Indices (Quarterly)
5	Operational and Technical Indices (Quarterly)
6	Information on Electric Customers (Quarterly)
7	Power Station Output, Sales, Billing and Collection (Monthly)
8	Purchases, Sales, Billing, and Collection (Monthly)
9	Purchases, Sales, Billing, and Collection (Monthly)
10	Accounts Receivable Information (Monthly)
11	Current Liability Information (Monthly)
12	Heat Sales Detail (Quarterly)
13	Wholesale Market Transactions in CES (Monthly)
14	Cash Settlement and Collection Results (Monthly)

APPENDIX A

Form 1

....licensee

Main indices for the .... quarter of 200...

No.	Indices			Measuring unit	Actual of the same period of last year	Quarter's		Accumulated	
				th kWh		Plan	Actual	Plan	Actual
1	Energy generation			th kWh					
2	Station use			th kWh					
				%					
3	Distributed		electricity	th kWh					
		Heat	hot water	Gcal					
			steam	Gcal					
4	Sales revenue			MNT million					
5	Other revenue			MNT million					
6	Total revenue			MNT million					
7	Total cost			MNT million					
		Of which:	Fuel	MNT million					
			Fixed	MNT million					
8	Operational profit/loss			MNT million					
9	Other profit/loss			MNT million					
10	Total profit/loss			MNT million					
11	Unit cost		electricity	MNT/kWh					
			heat	MNT/kWh					
12	Total number of employees			pers.					
13	Wage fund			MNT million					
14	Average salary			MNT					
15	Fixed assets			MNT million					
16	Current assets			MNT million					
		Of which:	spare parts	MNT million					
17	Accounts Payable			MNT million					
		Of which:	to Baganuur	MNT million					
			to Shivee-Ovoo	MNT million					
			to Shariin Gol	MNT million					
			UB Railway	MNT million					
			National Tax Authorit	MNT million					
			Others	MNT million					
18	Accounts Receivable			MNT million					
		Of which:	energy	MNT million					
			others	MNT million					
19	Fuel rate		electricity	g/kWh					
			heat	kg/cal					
20	coal consumption			ton					
21	Quality			kcal/kg					
22	Coal price at mines			MNT					
23	Mazut consumption			ton					
24	Number of equipment rehabilitated (major repair)								
		Of which:	turbine-generators, boilers and transformers						
			others						
25	Total cost of major repair			MNT million					
		Of which:	turbine-generators, boilers and transformers	MNT million					
			others	MNT million					
26	Minor investment /a			MNT million					
27	Investment			MNT million					
28	Social cost			MNT million					
29	Number of breakdown (no generation)								
		Undistributed electricity		th kWh					
		Undistributed heat		Gcal					
30	Breakdowns resulted in limitation of generation (1st cat								
		Undistributed electricity		th kWh					
		Undistributed heat		Gcal					
31	Number of accidents								
32	Number of fire								
33	Number & duration of boiler breakdowns			no&hour					
34	Number & duration of turbine breakdowns			no&hour					
35	Non-compliance against the schedule of the NDC			th kWh					

Executive Director

Chief Accountant

Note : a/ Own investment utilizing after tax profit mainly for upgrading equipment with frequent breakdowns.

APPENDIX A

Form 2

...electricity importation licensee
Main indices for the ..quarter of 200.

indices		Measuring unit	Months of the quarter			Quarterly	Accumulated
Imported	electricity	th kWh					
	Excessive load	MW					
Exported	electricity	th kWh					
	Accounted for export	th kWh					
	Unaccounted for export	th kWh					
Net imported for payment		th kWh					
Payment for net imported		US$					
of which: availability payment		US$					
exrate at the end of month		MNT per US$					
Average price per KWh at border		US$					
Total payment due	to Russia	MNT million					
	Custom duty	MNT million					
	VAT	MNT million					
	TOTAL	MNT million					
Actual payment							
to Russia	Beginning balance	MNT million					
	Monthly payment	MNT million					
	Ending balance	MNT million					
Custom duty	Beginning balance	MNT million					
	Monthly payment	MNT million					
	Ending balance	MNT million					
VAT	Beginning balance	MNT million					
	Monthly payment	MNT million					
	Ending balance	MNT million					
TOTAL	Beginning balance	MNT million					
	Monthly payment	MNT million					
	Ending balance	MNT million					
Average price including VAT and custom duties		MNT/kWh					

Contract condition for the quarter :

a/ availability		MW	% of accounted for export	
b/ price of 1 KWh		US$	Penalty for excessive load	
c/ price for 1MW		US$		

Executive Director
Chief Accountant

APPENDIX A

Form 3

...…transmission licensee
Main indices of the …quarter of 200.

No	Indices	Measuring unit	Actual of the same period the last year	Current quarter's		Accumulated	
				Plan	Actual	Plan	Actual
	A. Sales						
1	Purchased electricity from generators	th kWh					
2	Average price	MNT					
3	Imported electricity	th kWh					
4	Average price	MNT					
5	Total purchased electricity	th kWh					
6	Average price	MNT					
7	Own use	th kWh					
8	Transmission loss	th kWh					
9	Transmission loss	%					
10	Distributed electricity	th kWh					
11	Average price	MNT					
12	O&M cost	MNT million					
13	Profit/loss	MNT million					
14	Number of employees	pers.					
15	Wage fund	MNT million					
16	Fixed assets	MNT million					
17	Current assets	MNT million					
	of which: spare parts	MNT million					
18	Accounts Payable	MNT million					
	of which: electricity	MNT million					
	others	MNT million					
19	Accounts Receivable	MNT million					
	of which: electricity	MNT million					
	others	MNT million					
20	Number of breakdown (no generation)						
	Undistributed electricity	th kWh					
21	Breakdowns resulted in limitation of generation (1st category)						
	Undistributed electricity	th kWh					
22	Number of accidents						
23	Number of fire						

to be continued

APPENDIX A

Form 3

continuation of Form -3

24	Number of equipment rehabilitated (major repair)						
	turbine-generators, boilers and transformers						
	others						
25	Total cost of major repair	MNT million					
	turbine-generators, boilers and transformers	MNT million					
	others	MNT million					
26	Minor investment /a	MNT million					
27	Investment	MNT million					
28	Social cost	MNT million					

B. Provision of technical backgrounds for new connections.

29	Number of applications for new connections						
30	Applied load	MW					
31	Number of applications approved						
	Approved load	MW					
32	Number of new connections						
	Load for new connections	MW					
33	Number of applications rejected						

C. Block outs

No	Classification of reasons	Number of block outs	Undistributed (th kWh)	Direct damage (MNT million)
1	Own responsibility			
2	Technical break downs			
3	Other licensees' responsibility			
4	Consumers' responsibility			
5	Force Major			
6	TOTAL			

Executive Director
Chief Accountant

APPENDIX A

Form 4

……….regulated heat distribution and supply licensee
Main indices for the … quarter of 200.

No	Indices	Measuring unit	Actual of the same period of the last year	Current quarter's		Accumulated	
				Plan	Actual	Plan	Actual
A. Technical and economic indices							
1	Purchased heat	th Gcal					
	Of which: PP (....................)	th Gcal					
	PP (....................)	th Gcal					
	PP (....................)	th Gcal					
2	Circulation water	th ton					
	Of which: PP (....................)	th ton					
	PP (....................)	th ton					
	PP (....................)	th ton					
3	Additional water	ton					
	Of which: PP (....................)	ton					
	PP (....................)	ton					
	PP (....................)	ton					
4	Temperature	C					
	Of which: PP (....................)	C					
	PP (....................)	C					
	PP (....................)	C					
5	Average price	MNT/Gcal					
	Of which: PP (....................)	MNT/Gcal					
	PP (....................)	MNT/Gcal					
	PP (....................)	MNT/Gcal					
6	Technical losses	Gcal					
	%	%					
7	Distributed heat	th Gcal					
8	Water per Gcal of heat	ton/Gcal					
9	Average selling price	MNT/Gcal					
10	Sales Billing	MNT million					
	Collection	MNT million					
11	Total cost	MNT million					
12	Profit/loss	MNT million					
13	Number of employees	pers.					
14	Wage fund	MNT million					
15	Average monthly salary	MNT					
16	Unit cost	MNT/Gcal					
17	Revenue per Gcal	MNT/Gcal					
18	Fixed assets	MNT million					
19	Current assets	MNT million					
	of which: spare parts	MNT million					
20	Accounts Payable	MNT million					
	of which: electricity	MNT million					
	others	MNT million					
21	Accounts Receivable	MNT million					
	of which: electricity	MNT million					
	others	MNT million					

to be continued

Form 4

continuation of Form -4

22	Number of equipment rehabilitated (major repair)						
	turbine-generators, boilers and transformers						
	others						
23	Total cost of major repair	MNT million					
	turbine-generators, boilers and transformers	MNT million					
	others	MNT million					
24	Minor investment /a	MNT million					
25	Investment	MNT million					
26	Social cost	MNT million					

note: First 4 indices shall be reported on the monthly basis.

B. Provision of technical backgrounds for new connections.

No	Indices	no.	Load Q sum Gcal/h	of which: Q heat Gcal/h	Q hot water Gcal/h	Q ventilation Gcal/h	Q steam Gcal/h
26	Number of applications for new connections						
27	Number of applications approved						
28	Number of applications rejected						

Note: attach a list of applicants rejected with reasons of rejections

C. Information on breakdowns in heat supply

No	Classification of breakdowns	Number of breakdowns	Duration (hours)	Undistributed (th Gcal)	Direct damage (MNT million)
29	Own responsibility				
	o.w: breakdowns				
	capacity limitation (1st category)				
	Accidents				
	Fire				
29	Technical faults				
30	Other licensees' responsibility				
31	Consumers' responsibility				
32	Force major				
33	TOTAL				

D. Dealing with consumers' grievances

No	Grievances	Current quarter: grievances received	Current quarter: resolved	Accumulated: grievances received	Accumulated: resolved
34	TOTAL				
	of which: on heat supply				
	on supply quality				
	on payment				
	on activities of bill writers				

Executive Director
Chief Accountant

APPENDIX A

Form 5

..electricity distribution and regulated supply licensee

Main indices for the ..quarter of 200.

No	Indices	Measuring unit	Actual of the same period of the last year	Current quarter's		Accumulated	
				Plan	Actual	Plan	Actual
	A. Sales						
1	Purchased electricity	th KWh					
2	Purchase price	MNT					
3	Technical losses	th KWh					
4	%	%					
5	Distributed electricity	th KWh					
6	Collection (w/o VAT)	MNT million					
7	Collection (with VAT)	MNT million					
8	Average selling price	MNT					
9	O&M cost	MNT million					
10	Profit/loss	MNT million					
11	Number of employees	pers.					
12	Wage fund	MNT million					
13	Fixed assets	MNT million					
14	Current assets	MNT million					
	of which: spare parts	MNT million					
15	Accounts Payable	MNT million					
	of which: electricity	MNT million					
	others	MNT million					
16	Accounts Receivable	MNT million					
	of which: electricity	MNT million					
	others	MNT million					
17	(major repair)						
	turbine-generators, boilers and transformers						
	others						
18	Total cost of major repair	MNT million					
	turbine-generators, boilers and transformers	MNT million					
	others	MNT million					
19	Minor investment /a	MNT million					
20	Investment	MNT million					
21	Social cost	MNT million					

to be continued

APPENDIX A

Form 5

continuation of Form-5

22	Number of breakdown (no generatio						
	Undistributed electricity	th KWh					
23	Breakdowns resulted in limitation of generation (1st category)						
	Undistributed electricity	th KWh					
24	Number of accidents						
25	Number of fire						
	B. Provision of technical backgrounds for new connections.						
26	Number of applications for new connections						
	Applied load	MW					
27	Number of applications approved						
	Approved load	MW					
28	Number of new connections						
	Load for new connections	MW					
29	Number of applications rejected						
	Unacceptable load	MW					

C. Block outs

No	Classification of reasons	Number of breakdowns	Duration (hours)	Undistributed (th KWh)	Direct damage (MNT million)
1	Own responsibility				
2	Other licensees' responsibility				
3	Consumers' responsibility				
4	Force Major				
5	TOTAL				

D. Dealing with consumers' grievances

No	Grievances	Current quarter		Accumulated	
		grievances received	resolved	grievances received	resolved
1	TOTAL				
	of which: on electricity supply				
	on supply quality				
	on payment				
	on activities of bill writers				

Executive Director
Chief Accountant

APPENDIX A

Form 6

week of next quarter)

.....................(Licensee). Consumers' structure

No	Indices			Branches' name										TOTAL	
				quarter	accum	quarter	accum	quarter	accum	quarter	accum	quarter	accum	quarter	accum
A	Number of consumers /1+2+3+4/														
	of which: entities	Monthly consumption	0-50000 kWh												
			50000-100000 kWh												
			100000-200000 kWh												
			5-10 million kWh												
			more than 10 million kWh												
1	Sub-total														
	Budgetary organizations	Monthly consumption	0-50000 kWh												
			50000-100000 kWh												
			more than 100000 kWh												
2	Sub-total														
	Residential: apartments	Monthly consumption	0-50 kWh												
			50-100 kWh												
			100-150 kWh												
			150-250 kWh												
			more than 250 kWh												
3	Sub-total														
	residential: ger	Monthly consumption	0-50 kWh												
			50-100 kWh												
			100-150 kWh												
			150-250 kWh												
			more than 250 kWh												
4	Sub-total														
B	Billed electricity (th kWh)		Entity												
			Budgetary												
			Residential: apt.												
			Residential: ger												
	TOTAL														
C	Collection	MNT thousand	Entity												
			Budgetary												
			Residential: apt.												
			Residential: ger												
	TOTAL														

Executive Director . . . .

Chief Accountant . . . .

APPENDIX A

Form 7

Monthly sales of the ………………….generation licensee. …../month/….200.

No	Indices		Measuring unit	……/month/				accumulated			
				Plan	Actual	%	Difference	Plan	Actual	%	Difference
	I. Electricity										
1	Generated electricity		th kWh								
2	Station use		th kWh								
			%								
3	Transmitted electricity		th kWh								
	Transmission network		th kWh								
	Direct sales		th kWh								
4	Average selling price		MNT/kWh								
	Transmission network		MNT/kWh								
	Direct sales		MNT/kWh								
5	Billing		MNT million								
	Transmission network		MNT million								
	Direct sales		MNT million								
	II.Heat										
6	Distributed heat		th Gcal								
	UBHN		th Gcal								
	Direct sales		th Gcal								
7	Average price		MNT/Gcal								
	UBHN		MNT/Gcal								
	Direct sales		MNT/Gcal								
8	Billing		MNT million								
	UBHN		MNT million								
	Direct sales		MNT million								
	III.TOTAL REVENUE										
9	Billing		MNT million								
10	Collection		MNT million								
	Transmission network		MNT million								
	UBHN		MNT million								
	Direct sales		MNT million								
11	Collection rate.		%								

Executive Director ....

Prepared by: ....

APPENDIX A

Form 8

Monthly sales of the………..electricity distribution and regulated supply licensee. …./month/ 200.

No	Indices		Measuring unit	…../month/				accumulated			
				Plan	Actual	%	Difference	Plan	Actual	%	Difference
1	Purchased electricity		th kWh								
2	Losses		th kWh								
			%								
		Technical	th kWh								
			%								
		Commercial	th kWh								
			%								
3	Distributed electricity		th kWh								
4	Average price		MNT/kWh								
5	Billed electricity		MNT million								
6	Collection		MNT million								
7	Collection rate		%								
8	Payment to		MNT million								
	Transmission network		MNT million								
	Others (debt reduction)		MNT million								
9	Spent for own operations		MNT million								

Executive Director ....

Prepared by ....

APPENDIX A

Form 9

Monthly sales of the ……….heat distribution and regulated supply licensee. …/month/ 200.

No	Indices		Measuring unit	...../month/				accumulated			
				Plan	Actual	%	Difference	Plan	Actual	%	Difference
1	Purchased electricity		th Gcal								
	of whuch:	UB PP-2	th Gcal								
		UB PP-3	th Gcal								
		UB PP-4	th Gcal								
		Darkhan PP	th Gcal								
		Erdenet PP	th Gcal								
2	Average price		MNT/Gcal								
3	Billing		MNT million								
4	Collection		MNT million								
5	Collection rate		%								
6	Payment to		MNT million								
		UB PP-2	MNT million								
		UB PP-3	MNT million								
		UB PP-4	MNT million								
		Darkhan PP	MNT million								
		Erdenet PP	MNT million								
7	Spent for own operation		MNT million								

Executive Director ....

Prepared by ....

APPENDIX A

Form 10

Accounts Receivable of the …………licensee. …/month/, 200.

No	Indices		AR balance at the same period of last year	Beginning balance	Ending balance	Change compared with the same period of last year	Change in the month
1	Total accounts receivable / 2+3+4 /						
2	from consumers						
	Residential	ger					
		others					
		Sub-total					
	Entities	Erdenet copper mine					
		MonRus Non-Ferrous Metals					
		Hotol Cement					
		Darkhan Metallurgical Plant					
		others					
		Sub-total					
	Budgetary	State					
		Capital city and provinces					
		Districts and soums					
		Sub-total					
3	from energy entities						
	of which:	UB PP-2					
		UB PP-3					
		UB PP-4					
		Darkhan PP					
		Erdenet PP					
		Transmission Network					
		UB EDN					
		DS EDN					
		EB EDN					
		Baganuur&Southeast EDO					
		others					
4	Other receivable						

Executive Director
Prepared by:

APPENDIX A

Form 11

Current liability of the ……………licensee. …/month/, 200.

No	Indices		AR balance at the same period of last year	Beginning balance	Ending balance	Change compared with the same period of last year	Change in the month
1	Total payable / 2+3+4+5+6+7 /						
2	Coal payable	Baganuur					
		Shariin gol					
		Shivee Ovoo					
		Tavan tolgoi					
		Aduu chuluu					
		Other					
		Sub-total					
3	Transportation payable	UB Railway					
		Other					
		Sub-total					
4	Tax payable	VAT					
		Corporate income					
		Insurance contribution					
		Other					
		Sub-total					
5	Short term loans	Current portion of LT project loan					
		Interest payable of LT project loan					
		Local com.bank loan & interest					
		Other					
		Sub-total					
6	Payable to energy entities						
	of which:	UB PP-2					
		UB PP-3					
		UB PP-4					
		Darkhan PP					
		Erdenet PP					
		Transmission Network					
		UB EDN					
		DS EDN					
		EB EDN					
		Baganuur&Southeast EDO					
		others					
7	Other payable						

Executive Director
Prepared by:

APPENDIX A

Form 12

(This form must be filled in and sent to the Legal Information & administration dept. within the first week of next quarter)

.....................(licensee): Heat sales

No	Indices	Measuring unit	Quarters			TOTAL	Accumulated
1	Total distribution	Gcal					
	steam	Gcal					
	hot water	Gcal					
3	Total revenue	MNT th					
	steam	MNT th					
	hot water	MNT th					
4	Steam 8-13 kgs/cm2	Gcal					
		MNT/Gcal					
		MNT th					
5	Steam 20 kgs/cm2	Gcal					
		MNT/Gcal					
		MNT th					
6	Joint ventures	m3					
		MNT/m3					
		MNT th					
7	Heat supply for entities	m3					
		MNT/m3					
		MNT th					
8	Measured heat	Gcal					
		MNT/Gcal					
		MNT th					
9	Foreigners' apt	m2					
		MNT/m2					
		MNT th					
10	Apartments	m2					
		MNT/m2					
		MNT th					
11		m2					
	Apartment condominium service contors	MNT/m2					
	(to be paid as a charge of intermed)	MNT th					
12	Dormitories	m2					
		MNT/m2					
		MNT th					
13	Basement	m2					
		MNT/m2					
		MNT th					
14	Ventilation	Gcal					
		MNT/Gcal					
		MNT th					
15	Hot water for entities	Gcal					
		MNT/Gcal					
		MNT/day					
		MNT th					
16	Hot water for apartments	pers.					
		MNT/day					
		MNT th					
17	Hot water for apartments	Gcal					
		MNT/Gcal					
	(to be paid as a charge of intermed)	MNT th					
18	Condensation	ton					
		MNT/ton					
		MNT th					

Executive Director
Chief Accountant

APPENDIX A

Form 12

Continuation of Form -12

.... (licensee) : Heat consumption

No	Indices		Measuring unit	Quarters			TOTAL	Accumulated
A	Consumers' structure	Entity	no.					
		Budgetary	no.					
		Apartment	no.					
		Sub-total	no.					
B	Consumption	Entity	m3					
			Gcal					
		Budgetary	m3					
			Gcal					
		Apartment	m2					
			Gcal					
C	Revenue	Entity	MNT th					
		Budgetary	MNT th					
		Apartment	MNT th					
		Sub-total	MNT th					

Executive Director
Chief Accountant

Form 13

Monthly Report of CES Wholesale Market

Month of: ____________

	Energy Balance kWh (kWh)
Net System Output	
UB2	
UB3	
UB4	
Darkhan	
Erdenet	
Net Import	
Sales to Single Buyer	
Transmission Losses	
Sales from SB to EDNs	
UBEDN	
Erd EDN	
Dar EDN	
Bag EDN	
NOLGO	
Total Sales to EDNs	

Generator Tariffs	**Energy (Tg/kWh)**	**Availability (Tg/KW/day)**
UB2		
UB3		
UB4		
Darkhan		
Erdenet		
Net Import:		
Import		
Export		

Form 13

Form 13 - Page 2

Single Buyer Transactions: Month of ____________

	Energy kWh	Energy Amount	Availability KW Days	Availability Amount	Total Amount
Purchases					
UB2					
UB3					
UB4					
Darkhan					
Erdenet					
Net Import:					
Import					
Export					
Totals					
Actual Wholesale Market Cost for the Month:					
Total Costs					
Price per kWh					

Sales	kWh	Amount
UBEDN		
Erd EDN		
Dar EDN		
Bag EDN		
NOLGO		
Totals		

Wholesale Market Status	Amount
Balance at Beginning of Month	
Purchases	
Sales	
Balance at End of Month	

Form 14

CES Settlement and Collection Results

(thousands of Tg)

CASH SETTLEMENTS

	W/O VAT	Incl. VAT
Cash Receipts of the Market Banker		
On Behalf of:		
UBEDN		
Erd EDN		
Dar EDN		
Bag EDN		
TOTAL RECEIPTS		
Cash Disbursements		
To Generators:		
UB2		
UB3		
UB4		
Darkhan		
Erdenet		
Import		
Total		
To Transmission Company		
To Distribution Licensees		
UBEDN		
Erd EDN		
Dar EDN		
Bag EDN		
Total		
TOTAL CASH DISBURSEMENTS		

Market Banker Cash Position	
Beginning Balance	
Receipts	
Disbursements	
Ending Balance	

Form 14

Form 14 - Page 2

CES Settlement and Collection Results

(thousands of Tg)

NON-CASH SETTLEMENTS

Offset Transactions	W/O VAT	Incl. VAT
UBEDN		
Erd EDN		
Dar EDN		
Bag EDN		
Total		
UB2		
UB3		
UB4		
Darkhan		
Erdenet		
Import		
Total		
Transmission Licensee		
TOTAL OFFSETS		

Licensee Collection Summary (000 Tg)

	Receipts				Collection %		
	Cash	Offset	Total	Amount Due	Cash	Offset	Total
UB2							
UB3							
UB4							
Darkhan							
Erdenet							
Import							
Transmission							
UBEDN							
Erd EDN							
Dar EDN							
Bag EDN							

Total composite collection rate for Generation Licensees
Total composite collection rate for Distribution Licensees

APPENDIX B: ADDRESSING THE NEEDS OF LOW INCOME CUSTOMERS

Addressing the Needs of Low Income Customers

Thomas V. Smith

PA Consulting

Mongolia Power and Heat Sector Reform Project
- Regional Technical Support for East Asia

Sponsored by U.S. Agency for International Development

9 August 2002

Situation

- The Energy Sector would like to recover all of its costs
- ERA would like to develop tariffs based on the cost to provide service
- It is difficult to raise the tariffs of households with low incomes
    - They have limited ability to pay
    - The politicians worry about them
    - They may resort to stealing electricity
- Because of the situation of low income households, there is considerable pressure to set all household tariffs too low
- A common result is that the Licensees do not recover enough revenue to cover their costs

Therefore, it is in the interest of ERA and the Licensees to find a way to ease the burden on low income customers while setting overall tariffs at a level that recover all the costs (especially in the CES)

PA

Basic Points

- In theory, since all kWh that households receive are basically the same, they should be priced equally
- If the income of the population (or a segment of the population) is not adequate to provide a minimal standard of living, then it should be the responsibility of the government to provide necessary assistance.
- In many cases, however, the government does not provide enough assistance
- In Mongolia, there is not a central governmental social service agency that identifies poor people.
- “Poor” customers should be allowed to purchase a minimum amount of electricity to carry out basic daily activities
- Targeting the correct population (identifying the customers in need) is a challenge
- Consumption limits should be established (Don’t let customers take advantage of low cost energy by wasting it or “reselling” it)
- The challenge is with the unmetered customers

PA

Identifying Customers in Need

Option A – Define all Pensioners as being in need of financial assistance

ADVANTAGES	DISADVANTAGES
Easy to identify this group	Some pensioners may not be poor
Pensioners have a lot of support from politicians	This group is only a small part of the total population of poor households
It would be relatively easy to "Sell" this type of subsidy to the politicians and the general public	

Identifying Customers in Need

Option B – Define persons living in Ger Districts as being in need of financial assistance

ADVANTAGES	DISADVANTAGES
Easy to identify these customers	We know that all people living in ger districts are not poor
Since electricity tariffs generally subsidize heat, and ger residents do not have central heat, this would be cost justified	We know that some people living in apartments are poorer than some people in ger districts

Identifying Customers in Need

Option C – Have Aimag, Sum, or City government officials define households in need of assistance

ADVANTAGES	DISADVANTAGES
The local officials should know the situation since they are closest	Subject to abuse by officials
Should be relatively easy to "Sell" to politicians	Consistency between governmental units

Identifying Customers in Need

Option D – Have Khoroo Governors and Bog Governors define households in need of assistance

ADVANTAGES	DISADVANTAGES
These elected officials have detailed census data on the families in their area	Subject to abuse by the officials
These officials are currently determining the distribution of certain aid to households	Problems with consistency between the various Khoroo or Bog areas

Identifying Customers in Need

Option E – Other Suggestions on defining households in need

ADVANTAGES	DISADVANTAGES

Lifeline Tariff Alternative

- **Identify a basic "Lifeline" amount of electricity necessary for daily living:**
    - Lighting
    - Refrigeration
    - Cooking
    - Etc

  Assume this is 75 kWh per month

- **Set the price for the lifeline kWh below cost and the amount above the lifeline above cost:**

  Example: Assuming that cost is 45 Tg per kWh:
  First 75 kWh per month = 40 Tg / kWh
  Consumption over 75 kWh = 50 Tg / kWh

  (Would have to set the tariff for consumption above the lifeline amount so the total cost is recovered)

The lifeline amount could vary with size of household:

1 –2 people = 75 kWh per month

Additional 20 kWh per month for each additional household member (above 2), for example

Lifeline Tariff Alternative

ADVANTAGES	DISADVANTAGES
Easy to apply (assuming the billing "system" can handle the two prices)	Provides advantages to customers that are not poor
Encourages conservation	Low consumption of electricity does not mean that households are poor
In the US and some other countries, this "Inverted" tariff structure was introduced both to encourage conservation and to provide a "Lifeline" for the poor.	Some low income households may need to use relatively high amounts of electricity

Designing the Tariff

Once the customers in need of assistance are determined, we must determine:

- How much of a discount to offer from the basic tariff (5%, 10%, etc.)
- The amount of the discount (Subsidy) in terms of Tg.
- Which customer classes should fund the subsidy
- The subsidy in terms of Tg/kWh to add to each tariff

Remember, the subsidy can be funded within the Household class or by all electricity consumers

In order to be manageable in terms of funding, it is recommended that no more than 20 to 25 percent of households be eligible for the reduced tariff, otherwise the amount of increase to other customers will be too large.

Consumption limits must be placed on the discounted kWh. Otherwise there will be abuse and waste

More Ideas Please

-
-
-
-
-

APPENDIX C: REQUIREMENTS FOR TARIFF APPLICATIONS

Requirements for Tariff Applications of Generation Licensees

General Instructions

This document contains instructions and required schedules that Licensees must submit when requesting a change in tariffs.

Licensees are reminded that it is their responsibility to submit information sufficient to clearly and transparently communicate the methods and assumptions used in order that the ERA and others can have a clear understanding of the Licensee's position

The Schedules contained herein, in many cases, are summary schedules. The Licensee should submit supplementary schedules (often called "Working Papers") to support the amounts in the required schedules.

All Schedules contained herein are to be submitted to the ERA in both hard copy and electronic format. Licensees are encouraged to also submit any working papers or supplemental information in electronic format as well. For the supplemental information that is not available in electronic format, please note that in the schedules.

Furnish the sources of information, when appropriate, on each schedule.

When amounts are shown, please include the unit of measure (kWh, KW, Tg, Millions of Tg, Tg per kWh, etc.)

SCHEDULES TO BE INCLUDED IN THE APPLICATION

Letter request to the ERA on submission of tariff proposal

Brief notes explaining grounds of the tariff proposal

Forecasted Balance Sheet for the following 12 month period

Supporting data for Balance Sheet Estimates including:

- Fuel (coal and Mazut inventories)
- Other (Spare parts, consumables) inventories
- Fixed Asset Cost
- Accumulated Depreciation
- Accounts Payable
- Short-Term Debt
- Other Current Liabilities
- Long-Term Debt
- Equity

Forecasted Income Statement for the following 12-month period. Revenue to be based on estimated sales at current tariffs

Supporting data for Income Statement Estimates including:

- Sales of electricity, heat, and steam (quantities at current tariffs)
- Fuel Cost (quantities and unit prices by type of fuel, transportation costs)
- Salary Expense
- Employee benefits and taxes
- Depreciation
- Current Maintenance
- Other operating expenses (overheads, business trips, communications, etc.)
- Social Costs
- Short-term Interest expense
- Long-term Interest expense (include debt service schedule for each main borrowing agreement)
- Tax expense

Allocation of Operating Expenses to Electricity and Heat, including detail of allocation methodology

Allocation of Fixed Assets to Electricity and Heat, including detail of allocation methodology

Estimates of rate of return, including recommended Return on Equity

Proposed Revenue Requirements for Electricity and Heat

Estimates of cross subsidy from electricity to heat,

Proposed Tariffs including:

- Energy Tariff (Tg/kWh)
- Availability Tariff (Tg/KW/day)
- Heat Tariff (Tg/Gcal)
- Industrial Steam Tariff
- Ancillary Services Tariff (if necessary)

Technical and Operating Parameters including:

- Fuel Rates
- Station Use
- Expected major outages of equipment
- Average availability by quarter (KW)
- Maintenance and major rehabilitation projects and schedules

Land agreement,

Explanation of actions being taken to improve operating results and control costs including:

- Improvement of fuel rates
- Reduction of Station Use
- Improvement of equipment availability
- Compliance with dispatch requirements
- Safety

Requirements for Tariff Applications of Distribution and Retail Supply Licensees

General Instructions

This document contains instructions and required schedules that Licensees must submit when requesting a change in tariffs.

Licensees are reminded that it is their responsibility to submit information sufficient to clearly and transparently communicate the methods and assumptions used in order that the ERA and others can have a clear understanding of the Licensee's position

The Schedules contained herein, in many cases, are summary schedules. The Licensee should submit supplementary schedules (often called "Working Papers") to support the amounts in the required schedules.

All Schedules contained herein are to be submitted to the ERA in both hard copy and electronic format. Licensees are encouraged to also submit any working papers or supplemental information in electronic format as well. For the supplemental information that is not available in electronic format, please note that in the schedules.

Furnish the sources of information, when appropriate, on each schedule.

When amounts are shown, please include the unit of measure (kWh, KW, Tg, Millions of Tg, Tg per kWh, etc.)

SCHEDULES TO BE INCLUDED IN THE APPLICATION

Letter request to the ERA on submission of tariff proposal

Brief notes explaining grounds of the tariff proposal

Forecasted Balance Sheet for the following 12 month period

Supporting data for Balance Sheet Estimates including:

- Inventories (Spare parts, consumables, etc.)
- Accounts Receivable
- Fixed Asset Cost
- Accumulated Depreciation
- Accounts Payable (Wholesale Market, Other)
- Short-Term Debt
- Other Current Liabilities
- Long-Term Debt

- Equity

Forecasted Income Statement for the following 12-month period. Revenue to be based on estimated sales at current tariffs

Supporting data for Income Statement Estimates including:
- Sales of electricity by Tariff Schedule (quantities priced at current tariffs)
- Wholesale Power Costs
- Salary Expense
- Employee benefits and taxes
- Depreciation
- Current Maintenance
- Bad Debt Expense
- Other operating expenses (overheads, business trips, communications, etc.)
- Social Costs
- Short-term Interest expense
- Long-term Interest expense (include debt service schedule for each main borrowing agreement)
- Tax expense

Allocation of Operating Expenses to Distribution and Retail Supply, including detail of allocation methodology

Allocation of Distribution Operating Expenses to voltage level (35 KV, 10&6 KV, 400 volts and below)

Allocation of Fixed Assets to Distribution and Retail Supply, including detail of allocation methodology

Allocation of Distribution Fixed Assets to voltage level (35 KV, 10&6 KV, 400 volts and below)

Estimates of rate of return, including recommended Return on Equity

Proposed Revenue Requirements for Distribution (by voltage) and Retail Supply

Proposed Tariffs including:
- 35 KV Distribution Tariff (Tg/kWh)
- 10&6 KV Distribution Tariff (Tg/kWh)
- 400 volt and below Distribution Tariff (Tg/kWh)
- Retail Supply Tariff (Tg/kWh)

Technical and Operating Parameters including:
- Energy Balance at each voltage level showing energy purchases, sales, and losses
- Maintenance and major rehabilitation projects and schedules

Accounts Receivable by category including:

B. Entities
   - 5 Largest Non-Budget Customers
   - Other Non-Budget Customers

  - 5 Largest Budget Customers
  - Other Budget Customers

C. Households

Land Agreement

Explanation of actions being taken to improve operating results and control costs including:

- Technical Loss Reduction Efforts
- Commercial Loss Reduction Efforts
- Collection of Accounts Receivable Efforts
- Improvement of service quality
- Safety

APPENDIX D: FIXED ASSET RELATED ISSUES

Fixed Asset Related Issues in the Context of the Regulated Power Sector

Thomas V. Smith

PA Consulting

Mongolia Power and Heat Sector Reform Project
- Regional Technical Support for East Asia

Sponsored by U.S. Agency for International Development

June 2003

Purpose

The purpose of this presentation is to explain and clarify issues related to Fixed Assets:

- Acquisition
- Financing
- Depreciation
- Maintenance
- Cost Recovery

The Power Sector has been restructured and is beginning to operate in a commercial mode.

Many of the concepts that were utilized in the Government Ownership period, especially the Socialist Period, must be reevaluated in light of the new environment.

International Accounting Standards for Fixed Assets

Summary of IAS 16

- **Property, plant and equipment should be recognised when (a) it is probable that future benefits will flow from it, and (b) its cost can be measured reliably.**
- **Initial measurement should be at cost.**
- **Subsequently, the benchmark treatment is to use depreciated (amortised) cost but the allowed alternative is to use an up-to-date fair value.**
- **Depreciation:**
  - Long-lived assets other than land are depreciated on a systematic basis over their useful lives.
  - Depreciation base is cost less estimated residual value.
  - The depreciation method should reflect the pattern in which the asset's economic benefits are consumed by the enterprise.
  - If assets are revalued, depreciation is based on the revalued amount.
  - The useful life should be reviewed periodically and any change should be reflected in the current period and prospectively.
  - Significant costs to be incurred at the end of an asset's useful life should either be reflected by reducing the estimated residual value or by charging the amount as an expense over the life of the asset.

International Accounting Standards for Fixed Assets (Continued)

Summary of IAS 16 **(Continued)**

Revaluations (allowed alternative):

- Revaluations should be made with sufficient regularity such that the carrying amount does not differ materially from that which would be determined using fair value at the balance sheet date.
- If an item of PP&E has been revalued, the entire class to which the asset belongs must be revalued (for example, all buildings, all land, all equipment).
- Revaluations should be credited to equity (revaluation surplus) unless reversing a previous charge to income.
- Decreases in valuation should be charged to income unless reversing a previous credit to equity (revaluation surplus).
- If the revalued asset is sold or otherwise disposed of, any remaining revaluation surplus is transferred directly to retained earnings (not through the income statement).

If an asset's recoverable amount falls below its carrying amount, the decline should be recognised and charged to income (unless it reverses a previous credit to equity).

Gains or losses on retirement or disposal of an asset should be calculated by reference to the carrying amount.

Accounting for Fixed Assets

When new equipment is purchased and installed, the original cost is recorded as a Fixed Asset in the Balance Sheet

Over the life of the asset, maintenance costs are charged as a current period expense in the Income Statement.

If the asset is improved (capacity increased, life extended, etc.), the cost is added to the fixed asset account.

If components are replaced, the cost of the old components are retired and the cost of the new components added to the value.

Over the life of the asset, depreciation expense is charged as a current period expense in the Income Statement

International Accounting Standards and Depreciation

Summary of IAS 4 – Depreciation Accounting

- **Assets with limited useful lives should be depreciated on a systematic basis over useful life using a consistent method.**
- **The lives are those for which the asset is actually expected to be used by the enterprise.**
- **Estimate of useful life must consider wear and tear, obsolescence, and legal or other limits to the use of the asset.**
- **Depreciation method should be changed only if circumstances change.**
- **If depreciation method is changed, the effect must be quantified and disclosed. Reason for change must also be disclosed.**
- **Depreciable lives should be reviewed periodically.**
- **Disclosures include:**
    - Depreciation method.
    - Useful lives or depreciation rates.
    - Depreciation expense.
    - Gross depreciable assets and accumulated depreciation.

Depreciation Defined

Depreciation is an Accounting Concept

It is utilized to charge the cost of assets to expense over their useful lives

The time period is the useful life of the assets

Depreciation base is generally cost less estimated residual value.

$$\text{Depreciation} = \frac{\text{Cost} - \text{Estimated Salvage}}{\text{Remaining Life}}$$

OR:

$$\text{Depreciation} = \frac{\text{Cost}}{\text{Remaining Life}}$$

Common Misconceptions of Depreciation

Depreciation is used for Valuation – NO

Asset values depend on economic factors

Annual Depreciation is to be used for:

- Maintenance of fixed assets – **NO**
- Paying interest on debt – **NO**

Annual depreciation does provide a cash flow, however. The owner must decide what to do with that cash flow.

Accumulated Depreciation is a "Fund" – NO

Depreciation in a Regulated Environment

The cost of fixed assets must be recovered from customers

This is accomplished by charging depreciation as a cost of service over the useful lives of assets

Depreciation is a charge to income that provides a cash flow. That cash flow can be used for various purposes. However, in the LONG-TERM it will be needed to:

- Repay Principle on debt (interest is repaid out of current earnings)
- Repay the owner for funds provided to acquire fixed assets

Of course, the owner can utilize the cash flow in other ways, however, it must be remembered that if the cash flow is used to pay for current period expenses such as maintenance, interest, salaries, etc. then the value of the company will deteriorate.

The owner may use cash flow to acquire additional fixed assets, thereby reinvesting in the business.

Debt Financing Issues

In the case of the power sector in Mongolia, all long-term debt is due to international soft loans, generally with low interest rates and grace periods.

The GOM borrows the money, then "On-lends" to the companies according to a subsequent agreement specifying interest and principle payments (debt service). This is accomplished once the facilities are completed.

When the company records the value of the new facilities, it should record the principle of the loan at the same time.

In the periods in which interest is due, the entity should record interest expense on the income statement and interest payable on the balance sheet. When the payment is made, the cash amount offsets the payable.

Tariffs are designed to include the current period interest expense. If the company does not pay the interest, it has used those funds for other purposes. The current level of collections is causing severe cash shortages for the Licensees.

Example 1 – Financial Aspects of Company A

An example is presented to illustrate the financial aspects of a regulated business

Assume that Company A is created. Fixed assets of 2,000 are acquired and financed 50% with debt (at a 10% interest rate) and 50% by the owner (equity).

Using a 5 year time horizon, the following assumptions are made:

- **Operating expenses of 800 per year**
- **Maintenance costs of 125 per year**
- **Equipment depreciated over a 5 year life**
- **Income tax rate of 40%**
- **Return on equity of 15%**
- **Net income paid out as dividends**

Pages 12 and 13 contain the financial statements of Company A. Annual Revenue is assumed to equal the Revenue requirement of Company A including Operating, Maintenance, Depreciation, Taxes, and Return on Investment (Interest plus 15% Return on Equity).

At the end of the 5 year life of Company A, there is 1,000 of cash, the amount needed to reimburse the owner for the original investment. Fixed Assets have been fully depreciated.

Example 1 – Financial Aspects of Company A

	Year 0	1	2	3	4	5
Balance Sheet						
Cash Balance	0	200	400	600	800	1,000
Equipment:						
Original Cost	2,000	2,000	2,000	2,000	2,000	2,000
Accumulated Depreciation		400	800	1,200	1,600	2,000
Net Fixed Assets	2,000	1,600	1,200	800	400	0
Equity	1,000	1,000	1,000	1,000	1,000	1,000
Long Term Debt (10%)	1,000	800	600	400	200	0
Income Statement						
Revenue (Note 1)		1,675	1,655	1,635	1,615	1,595
Operating Expenses						
Operating Expenses		800	800	800	800	800
Maintenance		125	125	125	125	125
Depreciation		400	400	400	400	400
Pre Tax Operating Income		350	330	310	290	270
Interest Expense		100	80	60	40	20
Taxable Income		250	250	250	250	250
Income Tax (40%)		100	100	100	100	100
Net Income		150	150	150	150	150

Example 1 – Financial Aspects of Company A

Cash Flow	Year 0	1	2	3	4	5
Inflows						
Revenue (Note 1)	0	1,675	1,655	1,635	1,615	1,595
New Equity	1,000	0	0	0	0	0
New Debt	1,000	0	0	0	0	0
Total Inflows	2,000	1,675	1,655	1,635	1,615	1,595
Outflows						
Operating Expenses	0	800	800	800	800	800
Maintenance	0	125	125	125	125	125
Interest Expense	0	100	80	60	40	20
Tax Expense	0	100	100	100	100	100
Debt Repayment	0	200	200	200	200	200
Purchase Equipment	2,000	0	0	0	0	0
Pay Dividend		150	150	150	150	150
Total Outflows	2,000	1,475	1,455	1,435	1,415	1,395
NET CASH FLOW	0	200	200	200	200	200

Example 2 – Financial Aspects of Company B

This Example assumes that Company B is the same as Company A, with the exception that the Regulator does not allow this company to earn a return on equity.

Pages 15 and 16 contain the financial statements of Company B. Annual Revenue is assumed to equal the Revenue requirement of Company B including Operating, Maintenance, Depreciation, Taxes (zero in this case), and Return on Investment (Interest only in this case).

In this example there is zero net income since Return on Equity is zero. Of course, income taxes will also be zero. With no net income, there are no dividends.

This is a similar situation to the current situation of the Licensees in Mongolia.

At the end of the 5 year life of Company B, there is 1,000 of cash, the amount needed to reimburse the owner for the original investment. Fixed Assets have been fully depreciated.

Example 2 – Financial Aspects of Company B

	Year 0	1	2	3	4	5
Balance Sheet						
Cash Balance	0	200	400	600	800	1,000
Equipment:						
Original Cost	2,000	2,000	2,000	2,000	2,000	2,000
Accumulated Depreciation		400	800	1,200	1,600	2,000
Net Fixed Assets	2,000	1,600	1,200	800	400	0
Equity	1,000	1,000	1,000	1,000	1,000	1,000
Long Term Debt (10%)	1,000	800	600	400	200	0
Income Statement						
Revenue (Note 1)		1,425	1,405	1,385	1,365	1,345
Operating Expenses						
Operating Expenses		800	800	800	800	800
Maintenance		125	125	125	125	125
Depreciation		400	400	400	400	400
Pre Tax Operating Income		100	80	60	40	20
Interest Expense		100	80	60	40	20
Taxable Income		0	0	0	0	0
Income Tax (40%)		0	0	0	0	0
Net Income		0	0	0	0	0

Example 2 – Financial Aspects of Company B

Cash Flow	0	1	2	3	4	5
			Year			
Inflows						
Revenue (Note 1)	0	1,425	1,405	1,385	1,365	1,345
New Equity	1,000	0	0	0	0	0
New Debt	1,000	0	0	0	0	0
Total Inflows	2,000	1,425	1,405	1,385	1,365	1,345
Outflows						
Operating Expenses	0	800	800	800	800	800
Maintenance	0	125	125	125	125	125
Interest Expense	0	100	80	60	40	20
Tax Expense	0	0	0	0	0	0
Debt Repayment	0	200	200	200	200	200
Purchase Equipment	2,000	0	0	0	0	0
Pay Dividend		0	0	0	0	0
Total Outflows	2,000	1,225	1,205	1,185	1,165	1,145
NET CASH FLOW	0	200	200	200	200	200

Example 3 – Financial Aspects of Company C

This Example assumes that Company C is the same as Company B, with the exception that the owner utilizes the net cash flow each year to acquire new assets.

Pages 18 and 19 contain the financial statements of Company C. Annual Revenue is again assumed to equal the Revenue requirement of Company C including Operating, Maintenance, Depreciation, Taxes (zero in this case), and Return on Investment (Interest only in this case).

In this example there is zero net income since Return on Equity is zero. Of course, income taxes will also be zero. With no net income, there are no dividends.

Fixed Assets increase each year since any available cash is reinvested in the business. This, of course, results in zero cash balances.

At the end of the 5 year life of Company C, there is zero cash, 1,000 of net fixed assets, and 1,000 of equity, the owner's initial investment.

Example 3 – Financial Aspects of Company C

	Year					
	0	1	2	3	4	5
Balance Sheet						
Cash Balance	0	0	0	0	0	0
Equipment:						
Original Cost	2,000	2,200	2,440	2,728	3,074	3,488
Accumulated Depreciation		400	840	1,328	1,874	2,488
Net Fixed Assets	2,000	1,800	1,600	1,400	1,200	1,000
Equity	1,000	1,000	1,000	1,000	1,000	1,000
Long Term Debt (10%)	1,000	800	600	400	200	0
Income Statement						
Revenue (Note 1)		1,425	1,445	1,473	1,511	1,560
Operating Expenses						
Operating Expenses		800	800	800	800	800
Maintenance		125	125	125	125	125
Depreciation		400	440	488	546	615
Pre Tax Operating Income		100	80	60	40	20
Interest Expense		100	80	60	40	20
Taxable Income		0	0	0	(0)	0
Income Tax (40%)		0	0	0	(0)	0
Net Income		0	0	0	(0)	0

Example 3 – Financial Aspects of Company C

Cash Flow	Year 0	1	2	3	4	5
Inflows						
Revenue (Note 1)	0	1,425	1,445	1,473	1,511	1,560
New Equity	1,000	0	0	0	0	0
New Debt	1,000	0	0	0	0	0
Total Inflows	2,000	1,425	1,445	1,473	1,511	1,560
Outflows						
Operating Expenses	0	800	800	800	800	800
Maintenance	0	125	125	125	125	125
Interest Expense	0	100	80	60	40	20
Tax Expense	0	0	0	0	(0)	0
Debt Repayment	0	200	200	200	200	200
Purchase Equipment	2,000	200	240	288	346	415
Pay Dividend		0	0	0	(0)	0
Total Outflows	2,000	1,425	1,445	1,473	1,511	1,560
NET CASH FLOW	0	0	0	0	0	0

APPENDIX E: ACCOUNTS RECEIVABLE AND BAD DEBT ISSUES

A Note on Accounts Receivable and Bad Debts

Background

The practice that has been followed in the energy sector of Mongolia for Accounts Receivable is to record an account receivable for electricity or heat as customers are billed. The receivable then remains on the balance sheet of the entity until either the customer pays or the Court determines that the amount is uncollectable. The result is that that there are some receivables on the balance sheets of the entities that have a high probability of never being collected. Also contributing to the situation is the fact that the accounts are not allowed to be written off for tax purposes prior to a court order. In addition, there is a perception among energy sector entities that if accounts are written off, then customers will not pay.

In 2001, at the time the 18 energy sector entities were spun off from the Energy Authority, the individual companies made an effort to identify receivables that they considered to be uncollectable for various reasons including:

1. Businesses that were dissolved or bankrupt or otherwise insolvent
2. Former customers that could not be located
3. Individuals considered extremely poor
4. Individuals who died or were imprisoned.

The amounts, estimated by the individual energy sector entities at that time were approximately 560 million Tg for entities and over 2 billion Tg for individuals, representing over 10% of the outstanding accounts receivable of 21.7 billion Tg at that time. The result was that the balance sheets of the restructured entities were somewhat more fairly stated, however, a significant portion of the remaining Accounts Receivable were not able to be collected.

Accounting Issues

International business management and accounting practices encourage prudent valuation of assets, including accounts receivable. A basic principle of International Accounting Standards (IAS) is that assets should be stated at their net realizable values and, following the fundamental principle of conservatism, we know that assets (including accounts receivable) should not be overvalued. IAS permits the use of the Direct Write Off method. Under the Direct method, accounts receivable remain on the balance sheet until it is determined that the probability of collection is relatively low. This is the basic method that has been used to date in the energy sector of Mongolia. However, waiting for a court order to be issued takes considerable time and results in receivables remaining on the balance sheet far too long in many cases. The evaluation of whether an account has a reasonable possibility of collection is, of course, a matter of judgment. It is the responsibility of management to use its best judgment to make the determination[1].

Prudent application of the Direct method requires that management review the outstanding accounts (especially those over 90 days old) on a continual basis and write those off for which the probability of collection is very low – even though the court has not yet issued an order. KEEP IN MIND THAT, EVEN THOUGH A RECEIVABLE HAS BEEN WRITTEN OFF, AN ENTITY CAN STILL PURSUE COLLECTION. In fact, the detailed customer records can still show the amount owed by individual customers until the court issues a ruling that the account cannot be collected. Also, individual customers do not have access to the energy supplier's

[1] The Write-off of bad debts reduces income and, possibly share price. Also, it affects taxable income. In addition, investors have different opinions on the value of accounts receivable and an audit is very important.

accounting records, so they do not know whether or not their account has been written off for accounting purposes or not. When the entity writes off an account, there is a corresponding expense on the Income Statement (Bad Debt Expense).

Cost Recovery

Entities should be allowed by ERA to recover a reasonable amount of Bad Debt Expense in tariffs. The reasonableness of the amount should be determined based on the efforts made by the entity to collect receivables and to prevent an unreasonable amount of debt from accumulating in the future. In other words, the company must be willing to disconnect customers who continually do not pay in order that the other paying customers do not have unreasonably high tariffs due to a large amount of Bad Debt expense.

Moving Forward

The issue of bad debt write-offs must begin with the broader subject of the management of accounts receivable by each of the individual entities. During the commercialization work at Eastern Energy System, a presentation titled “Managing Accounts Receivable and Improving Collections” was made outlining some very basic issues. That presentation is attached and may be useful to other energy sector companies. In order to have a clearer picture of the situation, entities should first “clean up” their Accounts Receivable by writing off the accounts that are truly hopeless including such items as:

- Bankrupt Customers currently receiving service
- Bankrupt Customers no longer receiving service (out of business)
- Customers that have died
- Customers that have moved
- Customers that otherwise cannot be located
- Accounts that are more costly to collect than they are worth

The management team of each entity is encouraged to examine the outstanding accounts receivable and write off those hopeless accounts as well as any others for which the probability of collection is extremely low. In fact, the companies should have a good reason for not writing off any account more than 90 days old. This will eliminate the old debts, producing a clearer picture of the real value of accounts receivable. In order to establish a reasonable level of bad debt expense to include in tariffs, we must not include an unreasonably high level of very old accounts.

Sector Recommendation E of the Commercialization Report of Eastern Energy System (Copy Attached) includes a Summary Action Plan to include an allowance for bad debt in tariffs. Task 1 calls for each Licensee to provide various information to ERA in order that an analysis can be performed. An important element of that information is the documentation of the collection policy and a description of the efforts made to collect outstanding accounts receivable. The ERA must be assured that Licensees are taking all measures possible, up to and including disconnection, in order to collect accounts. After receiving each licensee’s proposal and holding open hearings, an order would be issued specifying the percent of revenue for each Licensee that should be included as bad debt expense in tariffs. It should be emphasized that the percent should be different for each Licensee to reflect the local conditions and mix of customers. In addition, Heat Distribution Licensees often have high accounts receivable balances during the heating season, but the balances generally are collected prior to the beginning of the next heating season.

The ERA should set the bad debt expense for each Licensee (as a percent of revenue) to cover a reasonable level of bad debt, given a vigorous collection effort by the Licensee. In fact, the ERA could utilize some incentive regulation in this area. Once the bad debt expense is established at a reasonable level, if the Licensee works hard to improve collections, it can be allowed to keep the additional amount. If, on the other hand, the Licensee does not work hard on collections and bad debts are greater than the amount included in tariffs, then the Licensee suffers a loss.

Examples of Accounting Treatment

Attached are examples of how the accounting entries are made and the resulting effect on two hypothetical companies. The examples show the effect on the Accounts Receivable balance due to:

- Billings to Customers
- Collections
- Write-off of Bad Debts

They also show the effects on the income of the companies due to:

- Bad debt expense included in tariffs
- The Write-off of Bad Debts
- Collection of accounts previously written off

Example I presents a situation where the Company was able to achieve a higher collection percentage than the one used to establish its tariffs, resulting in a positive effect on its income. Example II, on the other hand, shows a company that achieved a collection percentage lower than the tariff assumption, resulting in a negative effect on its income.

Hopefully those examples will help the reader see how the principles are applied.

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PA Consulting

Sector Recommendation E

The ERA should include an allowance for bad debt in the wholesale and retail tariffs to recognize that virtually no suppliers collect 100% of the amounts billed to customers.

Background of the Issue

Collection of accounts receivable is a problem throughout Mongolia; however, the ERA will not include an allowance for bad debts in the tariffs. It is recommended that EES and the other licensees lobby ERA and the Government of Mongolia to include an allowance for bad debt in the wholesale and retail tariffs to recognize that virtually no suppliers collect 100% of the amounts billed to customers.

In accordance with International Accounting Standards, bad debt expense should be recorded to recognize that 100% of the revenue recorded in a particular period will not be collected and also to prevent the Accounts Receivable balance from being overstated.

Preconditions

ERA must be willing to increase retail (and wholesale) tariffs in order to allow Licensees to recover the bad debt expense from customers.

Summary Action Plan

Task	Responsibility	Time Frame
1. Require each Licensee to provide the following information by 31 March 2003: a) Revenue recorded (billings) and collections by year for the prior 5 years b) An aging of its Accounts Receivable at 31 December 2003. c) Documentation of its collection policy and efforts made to collect outstanding Accounts Receivable. d) A proposal of the level of Bad Debt expense (as a percent of revenue) to be included in its tariff.	ERA	Request Issued 01 January 2003 Deadline for completion is 31 March 2003
2. Analyze the information provided by Licensees and provide a report summarizing the findings	ERA Staff	01 May 2003
3. Hold open hearings on the Issues	ERA	01 June 2003
4. Issue an order specifying the bad debt expense as a percent of revenue that will be included in tariffs for each licensee at the time the tariffs are adjusted	ERA	30 June 2003

<table>
<tr><td colspan="3" align="center"><u>Sector Recommendation E</u>
The ERA should include an allowance for bad debt in the wholesale and retail tariffs to recognize that virtually no suppliers collect 100% of the amounts billed to customers.</td></tr>
<tr><td>5. Follow through and include the bad debt expense in tariffs.</td><td>ERA</td><td>During 2003, when tariffs are adjusted</td></tr>
<tr><td colspan="3"><u>Results Expected</u>

1. More reasonable cost recovery for Licensees
2. Makes the bad debt situation more transparent.</td></tr>
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Example I of the Accounting Entries Related to Bad Debts and Accounts Receivable

Electricity Distribution Company ABC

(All Amounts in thousands of Tg)

Assumptions:

1 ERA has determined that a reasonable bad debt expense for Company ABC to include in tariffs is 2% of Revenue
2 The level of Accounts Receivable at the beginning of the year excludes "Hopeless" accounts
3 Company ABC continually monitors its Accounts Receivable and writes them off when the probability of collection is low
4 In the second quarter, the Company collected 10,000 Tg of accounts that it previously wrote off, increasing income

	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Total Year
Balance Sheet Components					
Accounts Receivable					
Beginning Balance	15,000	14,950	14,750	14,550	15,000
Billed Electricity	12,000	11,000	10,000	14,000	47,000
Collections	11,800	11,000	10,000	13,800	46,600
Write-off of Bad Debts	250	200	200	260	910
Ending Balance	14,950	14,750	14,550	14,490	14,490
Income Statement Components					
Bad Debt Expense included in Tariff	240	220	200	280	940
Write off of Bad Debts	250	200	200	260	910
Collection of accounts previously written off		10			10
Effect on Net Income	(10)	30	0	20	40

Statistics: Collection Percentage (Collections as a % of Billings) equals: 99.2%

RESULT: Company ABC achieved a collection percentage of 99.2% as opposed to the assumed 98%
The Accounts Receivable balance declined
The Effect on net income was positive

Example II of the Accounting Entries Related to Bad Debts and Accounts Receivable

Electricity Distribution Company XYZ

(All Amounts in thousands of Tg)

Assumptions:

1 ERA has determined that a reasonable bad debt expense for Company XYZ to include in tariffs is 2% of Revenue
2 The level of Accounts Receivable at the beginning of the year excludes "Hopeless" accounts
3 Company XYZ continually monitors its Accounts Receivable and writes them off when the probability of collection is low
4 In the third quarter, the Company collected 15,000 Tg of accounts that it previously wrote off, increasing income

	Quarter 1	**Quarter 2**	**Quarter 3**	**Quarter 4**	**Total Year**
Balance Sheet Components					
Accounts Receivable					
Beginning Balance	15,000	15,150	15,430	15,290	15,000
Billed Electricity	12,000	11,000	10,000	14,000	47,000
Collections	11,600	10,500	9,900	13,800	45,800
Write-off of Bad Debts	250	220	240	260	970
Ending Balance	15,150	15,430	15,290	15,230	15,230
Income Statement Components					
Bad Debt Expense included in Tariff	240	220	200	280	940
Write off of Bad Debts	250	220	240	260	970
Collection of accounts previously written off			15		15
Effect on Net Income	(10)	0	(25)	20	(15)

Statistics: Collection Percentage (Collections as a % of Billings) equals: 97.5%

RESULT: Company XYZ achieved a collection percentage of 97.4% as opposed to the assumed 98%
The Accounts Receivable balance increased
The Effect on net income was negative